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DEVELOPMENT OF WELL TEST ANALYSIS TECHNIQUES FOR APPLICATIONS IN OIL SANDS

A STUDY PREPARED BY

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DEVELOPMENT OF WELL TEST ANALYSIS TECHNIQUES FOR APPLICATIONS IN OIL SANDS

A. INTRODUCTION AND OBJECTIVE

1. STATE OF THE ART

Reservoir engineering is primarily concerned with optimizing hydrocarbon recovery from a reservoir. Effective optimization, in turn, is critically dependent upon a sound knowledge of certain key reservoir parameters. Since reservoirs in general, and oil sands/heavy oil reservoirs in particular, are very heterogeneous, the task of quantifying those parameters is correspondingly complex.

In a conventional oil or gas reservoir, three traditional reservoir description techniques are available. These are coring, logging and well testing. Coring and logging provide valuable petrophysical information about the reservoir, but are limited spatially in that they sample the system at or very near the wellbore. In contrast, well testing is capable of sampling a much larger volume within the reservoir. Furthermore, whereas coring and logging both measure parameters on a disturbed system, well testing gathers its measurements in situ.

In virgin oil sands, only two of the three traditional reservoir description techniques, coring and logging, have been employed. To carry out a well test, some means of injecting into or producing from the formation is required. Although oil sand exhibits virtually zero productivity, it is capable of accepting gas at low rates without fracturing the formation. However, gas injection would introduce into the oil sand a non-indigenous fluid phase, which enters the reservoir by displacing some portion of an indigenous mobile phase (i.e., water). Interpretation of data from such a well test would require a supporting theoretical framework, since current well test theory assumes single-phase flow.

In summary, classical well test theory involves single-phase flow. However, well testing techniques for virgin oil sand are likely to require the injection of a non-indigenous fluid, such as a gas. This represents a displacement process, which is not encompassed within the current repertoire of practical well test analysis techniques.

2. INCENTIVE FOR DEVELOPING WELL TESTING IN OIL SANDS

In non-mineable oil sands, the need for characterization of key flow parameters is particularly critical in improving oil recovery. One of the most important such parameters is effective vertical permeability. This parameter plays a large role in recovery efficiency even when the recovery process is nominally horizontal. In the case of gravity-controlled or other vertical recovery processes, effective vertical permeability is a cardinal determinant of success or failure.

The extension of well test analysis techniques to encompass oil sands would provide an important new tool in the description of these reservoirs. In particular, if well testing techniques could be used to derive an in situ estimate of effective vertical permeability, or of vertical-to-horizontal permeability ratio, this would represent a useful technical advance.

3. STUDY OBJECTIVE

The general objective of this study was to demonstrate a framework for the application of well test analysis techniques in oil sands.

A more specific objective was to develop practical well test analysis techniques for determining vertical-to-horizontal permeability ratio in oil sands.

B. EXECUTIVE SUMMARY

1. ENGLISH

The ratio of vertical-to-horizontal permeability is often influential, and sometimes of critical importance, in the success of in situ recovery techniques in oil sands. To date, no theoretically sound approaches to determining this ratio in oil sands have been suggested. This study describes the development of well test analysis techniques which can be used to determine vertical-to-horizontal permeability ratio in a virgin oil sand.

More generally, the study also demonstrates that, under suitable circumstances, single-phase flow theory can be adapted to describe multi-phase displacement.

Well testing in a virgin oil sand is likely to require the injection of a mobile, non-indigenous fluid, such as a gas, so that a measurable pressure disturbance can be created and subsequently analyzed to determine certain reservoir parameters. The fundamental premise of this study is that the pressure disturbance created in these circumstances propagates outward much more rapidly than the interface between the injected and indigenous fluids. Accordingly, pressure response data measured at a well located beyond the fluid-fluid interface may be analyzed using single-phase flow theory, even though there is multi-phase flow in the invaded region. This facilitates the application of existing single-phase unsteady-state flow theory and associated well test analysis techniques.

The study examines two well test analysis methods which determine vertical permeability - Prats and Ehlig-Economides & Ayoub (EE&A). These single-phase flow techniques are then modified to accomodate the injection of a gas, so that vertical-to-horizontal permeability ratio may be determined in a virgin oil sand. In so doing, the analysis techniques are enhanced, not only for oil sands situations, but also for more general applications.

2. FRENCH

2. FRENCH

Dans l'application des techniques de recouvrement de sable bitumineux, le rapport de la perméabilité verticale et horizontale est souvent influent, et parfois d'importance critique. A jours, aucune approche théorique afin de déterminer ce rapport dans les sables bitumineux a été suggere. Cette étude élabore le dévelopment des techniques d'analyse de test de puit qui peuvent être utilisé afin de déterminer le rapport de la perméabilité verticale et horizontale dans les sables bitumineux vierges.

En général, l'étude démontre que donner des conditions convenables, la théorie de régime à une phase peut être modifié afin de décrire le déplacement des plusieurs phases.

Les tests de puit dans les sables bitumineux vierges peuvent demander l'injection d'un fluide non-indigène, comme le gaz, pour ainsi créer une variation de pression mesurable ensuite analysable, ce qui permet l'obtention des certains paramètres du réservoir. La premisse fondamentale de cette etude est que la variation de pression dans ces circonstances se propage vers l'extérieur plus rapidement que l'interface de fluide injecté et de fluide indigène. De la même façon, les données de réponse de pression mesurée pour un puit situé au delà de l'interface liquide-liquide peuvent être analysées à l'aide de la théorie du régime à une phase, malgré la présence d'un regime à phases multiples dans la zone envahié. Ceci facilite l'application des théories déja existantes pour les régimes non établis a une phase et les techniques d'analyse de test de puit s'y rattachant.

Cet étude examine deux méthodes d'analyse de test de puit pour la détermination de la perméabilité verticale - Prats et Ehlig-Economides & Ayoub (EE&A). Ces techniques des régimes à une phase sont ensuite modifiées pour l'injection d'un gaz, de cette manière le rapport de la perméabilité verticale et horizontale peut se faire pour les sables bitumineux mais aussi pour des applications plus générales.

C. CONCLUSIONS

1. Vertical-to-horizontal permeability ratio (k_v/k_h) is a key parameter in numerous recovery schemes, including many which are nominally described as horizontal. Use of cores and logs to determine this parameter is both complex and uncertain. In reservoirs where the oil is mobile, existing well testing techniques may provide a means of measuring this parameter in situ. In a virgin oil sand, however, the existing single-phase flow techniques are inadequate, both practically and theoretically.

2. Under suitable circumstances, single-phase flow theory can be adapted for application in a field situation where two-phase displacement is occurring.

3. Based on the foregoing result, well test analysis techniques have been developed which permit determination of vertical-to-horizontal permeability ratio (k_v/k_h) in a virgin oil sand.

4. Two such techniques have been developed by modifying existing single-phase flow techniques for determining vertical permeability. These are the Prats analysis technique and the Ehlig-Economides and Ayoub (EE&A) analysis technique.

5. Major modifications to the testing procedure include the injection of a non-indigenous fluid, such as gas, to create a two-phase displacement, and the utilization of a second (offset) well which serves as an additional observation point.

6. Major modifications to the analysis technique include the use of rate normalization and the introduction of special techniques for pressure averaging, as well as revisions to the basic procedure for determining k_v/k_h.

7. The use of rate normalization permits a gradually varying bottomhole gas injection rate. Two field operating conditions for which the analysis techniques are valid include constant surface injection rate and constant surface injection pressure.

8. The principal disadvantage of the modified methods is that they require a second well. However, as explained below, this apparent disadvantage yields dividends in accuracy and self-consistency.

9. The principal advantage of the modified methods is that the data obtained at the second well eliminates the need to seek values for certain key input parameters from external sources of uncertain reliability. Instead, values for those parameters are determined as an integral part of the well test data analysis.

10. Calculated values of k_v/k_h by either of the two analysis techniques are independent of fluid viscosity.

11. Pressure response at the offset well during two-phase displacement is independent of relative permeability characteristics, provided gas invasion at the offset well is not excessive.

D. RECOMMENDATIONS

1. A field test of the modified techniques developed in this study should be implemented in an oil sand. The test should include two wells spaced 10 to 20 meters apart, and should maximize the use of surface recording bottomhole pressure gauges. A gas such as nitrogen should be injected, preferably under conditions of constant surface pressure to simplify the operation.

2. Since the modified techniques offer some added advantages in terms of data reliability or self-consistency, their application beyond oil sands should be considered. For example, in a conventional oil or gas situation, where the well is producible, or where the indigenous fluid can be injected, two-phase flow techniques may not be required. However, it may still be advantageous to employ two wells and apply the modified techniques because of the resulting increased reliability in determining k_v/k_h.

E. SUMMARY

1. TECHNICAL TOPICS

The basic structure of technical material presented in this report is as follows:

1) Definition of terms and units, and outline of basic concepts.

2) Examination of horizontal flow, comparing both single and two-phase regimes.

3) Examination of two single-phase vertical flow well testing techniques from which vertical permeability can be determined. The techniques are those of Prats and Ehlig-Economides & Ayoub (EE&A).

4) Modifications required to adapt each of these two techniques to two-phase flow (i.e., gas injection into an oil sand).

5) The field testing procedures and well test analysis techniques for the modified Prats and modified EE&A methods.

6) Description of cases which examine sensitivities to various reservoir and operating parameters.

7) Considerations in selecting a suitable reservoir in which to apply these techniques.

8) Examples of input files used in the IMEX300 model runs.

2. REPORT OUTLINE

Section A summarizes the state of the art with respect to determining vertical flow characteristics in a virgin oil sand, and describes the objective of the study.

Section B presents an executive summary of the study results.

Sections C and D outline respectively the major conclusions and recommendations arising from the study.

Section F defines relevant terms and outlines some basic considerations in single-phase flow. It then presents a rationale for the application of single-phase flow to two-phase displacement provided that certain conditions are met. Finally, the general features of a well testing technique which involves two-phase displacement, but which adapts single-phase flow theory, are suggested.

Section G describes the numerical model used throughout the study and the basic reservoir configuration represented. Before dealing with vertical flow, the consequences of two-phase horizontal flow are examined. In addition, some key concepts which are incorporated subsequently into the modified well testing techniques are identified. These include the addition of an offset well in the testing configuration and the application of rate normalization to adjust measured pressures. Section G also examines the effect on pressure response of relative permeability and offset well distance. Also, limitations of attempting to use a shut-in test, rather than a flow test, are illustrated.

Section H describes the Prats and EE&A single-phase well testing techniques for determining vertical permeability. Some of the limitations of these techniques are also enumerated.

Sections I and J are concerned with the Prats technique. Section I discusses the modifications which improve the Prats technique, even when only single-phase flow is applicable. The cost of these improvements is reflected in the requirement for a second (offset) well. Section J incorporates all of the previously described modifications into a description of the modified Prats well testing technique. This includes both the field procedure for testing the well and the analysis of the resulting test data (sub-sections 4b) and 4c)).

Section K encompasses for the EE&A technique those areas which are described in Sections I and J for the Prats technique. These include a discussion of the modifications to the EE&A technique which permit its adaptation to two-phase flow, followed by a description of the modified technique. Both the field testing procedure and the well test analysis method are outlined in sub-sections 3b) and 3c).

Section L describes the results of several cases generated through numerical modelling and analyzed using the modified Prats

technique. These include the influence of distance to the offset observation well, random permeability distribution and the presence of a higher permeability layer in an otherwise homogeneous system.

Section M presents cases generated through numerical modelling which were analyzed using the modified EE&A technique. The question of deriving suitable methods for calculating average pressure at the offset well is addressed, and specific guidelines are prescribed. Also illustrated is the utilization of data determinable from the well test to improve the ultimate result - calculation of vertical-to-horizontal permeability ratio. A series of cases examines the influence of hydrostatic gradient (head), a variety of zonal configurations within the reservoir, wellbore damage and the imposition of a constant bottomhole pressure.

Section N describes certain theoretical limitations of the two well test analysis techniques, based on the assumptions employed in their development. The extent to which some of these techniques can be relaxed while still achieving valid results is also discussed.

Section O lists the references used in this work.

Appendix 1 presents the symbols and units used in this report, and Appendix 2 provides examples of input data employed in some of the model cases.

F. TECHNICAL BACKGROUND

1. DEFINITIONS

a) Definitions of Terms

Following are a number of definitions of terms which are used in this report. They pertain to the locations of pressure observation points and to various types of well test procedure.

SAME-WELL OBSERVATION POINT:

Refers to the interval, located at the same well as the injector/producer but vertically separated from the injection/production interval, at which pressure response is observed.

OFFSET-WELL OBSERVATION POINT:

Refers to the interval, located at a well some distance from the injector/producer, over which pressure response is observed.

DRAWDOWN:

Refers to the pressure decline due to production.

BUILD-UP:

Refers to the pressure increase due to shut-in following production.

CHARGE-UP:

Refers to the pressure increase due to injection.

FALL-OFF:

Refers to the pressure decline due to shut-in following injection.

b) Definitions of Symbols and Units

Definitions of symbols used within the text are provided in Appendix 1, along with the corresponding units. Note that SI or SI-compatible units are used. Accordingly, equations which are cited from the references, and which were expressed originally in traditional units, have been converted to SI-based units for presentation in this report.

2. SINGLE-PHASE FLOW - BASIC THEORETICAL CONSIDERATIONS

A well test involves a period of controlled production or injection, and may include a period when the well is shut in. Throughout these periods, pressures are measured, either at the injection/production well, or at a nearby (i.e., offset) well, or both. These flow rates, together with the corresponding pressure responses, are then analyzed to determine values of reservoir parameters such as permeability and average reservoir pressure.

The tractability and versatility of well test analysis techniques relies on the fact that they are based on single phase flow theory. This results in linear differential flow equations, which are amenable to analytic solutions. Because of the linearity of the flow equations, solutions to complex flow problems can be built by simple addition of more basic solutions. This has facilitated the development of relatively straightforward well testing techniques, such as pressure build-up and drawdown tests.

In theory, either injection or production may be used to initiate fluid movement, and thereby implement a well test within a reservoir. In a virgin oil sand, however, injection of a mobile fluid, such as a gas, may be the only practical means of initiating that flow. The two phase flow situation which would occur in an oil sands well test (i,e., injection of a gas to displace formation water), gives rise to non-linear differential equations which are not generally amenable to analytic solutions. Accordingly, a body of well test theory and techniques for multi-phase fluid displacement has not been developed.

3. APPLICATION OF SINGLE-PHASE THEORY TO TWO-PHASE FLOW THEORY

In this section, a rationale will be presented which supports the general approach followed in this study. That approach utilizes

single-phase flow theory, with certain modifications, to analyze the multi-phase fluid displacement which would occur during injection into an oil sand.

In single phase flow, when injection or production occurs at a well, a pressure disturbance, or transient, is propagated throughout the system. The velocity of this disturbance is a function of the properties of the reservoir. The amplitude of the disturbance is a function both of the reservoir properties and of the rate of fluid injection/production.

The velocity at which the single-phase flow disturbance propagates outward is traditionally defined in terms of the investigation radius, r_s, reached by the disturbance after a time, t, as follows[1]:

$$r_s = 0.5879*(kt/(\phi uc))^{0.5} \qquad \text{(F-1)}$$

This relationship is illustrated in Figure F-1 for a specific set of reservoir parameters indicative of virgin oil sand properties.

If a non-indigenous fluid, such as a gas, is injected, an interface will be formed between the displaced and displacing phases. The radius of that fluid interface is defined as follows:

$$r_f = 0.5642*(qt/(h\phi))^{0.5} \qquad \text{(F-2)}$$

where injection at a constant rate, q, is assumed.

Figure F-2 compares the relationships defined by equations F-1 and F-2, for a plausible set of sub-fracturing conditions in an oil sand. As indicated, at any given time, the distance moved by the investigation radius is very much larger than that moved by the fluid interface.

This contrast between the lower velocity of the fluid-fluid interface and the higher velocity of the pressure disturbance is of fundamental importance. For even though a second mobile fluid has now been introduced into the system, the pressure disturbance, whose amplitude and velocity provide information on the reservoir, is from time zero always propagating outward from the well, beyond the fluid-fluid interface. That is, the pressure transient is propagating outward in the portion of the reservoir which still contains the indigenous fluids. Thus, the pressure transient is sampling the uninvaded, single-phase flow portion of the reservoir.

This phenomenon suggests that single phase flow theory can be applied to the analysis of this type of multi-phase flow situation,

provided that the pressure data to be analyzed are recorded at an appropriately chosen location within the system.

4. GENERAL WELL TEST STRUCTURE

Based on the foregoing considerations, a well test which involves the injection of a non-indigenous fluid will require that pressure data be recorded within the non-invaded portion of the reservoir (i.e., at some distance from the injector). That is, the pressure response measured at the point of injection will not be consistent with single-phase flow theory, since it is located within the invaded zone. However, a remote observation point can monitor pressure response during a time interval following the arrival of the pressure disturbance but prior to significant interference due to invasion by the fluid interface.

Accordingly, the reliability of a well test which attempts to adapt single-phase flow theory to this type of multi-phase fluid displacement situation will benefit from the placement of an observation well at some suitably located distance from the injector. This point is elaborated in subsequent sections of the report.

G. COMPARISON OF SINGLE-PHASE AND TWO-PHASE HORIZONTAL FLOW

1. SUMMARY DESCRIPTION OF NUMERICAL MODEL

As noted previously, differential equations governing multi-phase flow are not amenable to general analytic solutions. Accordingly, to establish the manner in which single-phase flow theory might by employable in analyzing the two-phase flow situations of interest, numerical modelling was used.

The model selected was IMEX 300, developed by Computer Modelling Group (CMG) of Calgary. This is a three-phase black oil simulator with gravity and capillary terms, capable of application in either two or three dimensions. Either Cartesian or cyclindrical coordinates may be used.

For purposes of this study, only a two-phase system with two-dimensional radial-vertical (r-z) geometry was required. The two phases were injected gas and indigenous mobile water. In a virgin oil sand, the bitumen is immobile for all practical purposes because of its high viscosity. Also, some portion of the connate water is retained in place by capillarity. Although, bitumen could have been represented as a third phase with very high viscosity, and the immobile portion of the connate water could have been reflected in the relatively permeability end points, it was deemed simpler to treat these effectively immobile fluids as part of the "solid" system.

2. MODEL CONFIGURATION AND RESERVOIR PARAMETERS

The model grid block configuration used throughout the study is summarized in Table G-1.

When purely horizontal flow was being investigated, only two layers, each 7.5 m in thickness, were employed. However, when vertical flow was being examined, the reservoir was represented by 15 layers, each 1.0 m thick. The radial configuration shown in Table G-1 was used throughout the study.

Table G-2 summarizes the initial conditions and reservoir parameters employed in the model. Not shown are the gas-water relative permeability curves, for which various functional forms

were used, depending on the case. These gas-water relative permeability curves are discussed and illustrated subsequently within this section.

The reservoir parameters shown in Table G-2 represent base case values. Many of these were varied and the results of those cases are discussed subsequently. Most notably, effective permeability was represented in both homogeneous and heterogeneous configurations, as well as with isotropic and anisotropic characteristics.

3. INJECTION WELL TEST - HORIZONTAL FLOW

a) Single-Phase Flow

To check the general reliability of the numerical model, a case was run to simulate water injection into the water-saturated reservoir (i.e., single-phase flow). Injection was at a constant rate of 0.05 M3/D. Figure G-1 compares the resulting model pressure charge-up curve with that generated from the analytical solution.

Calculation of formation permeability based on the numerical model results, and utilizing the latter portion of the charge-up curve, yields a value of 9.439E-05 ΔM2, compared with the input value of 9.869E-05 ΔM2. The 4.4% discrepancy suggests a good correspondence.

b) Two-Phase Flow

Figure G-2 compares the pressure charge-up response for water injection (single-phase flow) with that of gas injection (two-phase displacement) at comparable bottomhole injection rates. The water injection curve corresponds to that illustrated in Figure G-1 for the model, and has a quite well defined straight-line character. As already noted, the slope of that straight line yields a reliable value of permeability. The gas injection curve, on the other hand, exhibits no well-defined linearity. This is to be expected. Sustained injection of the more mobile gas creates a continually enlarging zone of higher transmissibility in the vicinity of the wellbore, reducing overall fluid resistance. As a consequence, the pressure required to sustain a given bottomhole gas injection rate increases more slowly.

To determine permeability from an injection well test, the slope of the pressure charge-up curve is required. However, as

illustrated above, this curve is not a reliable indicator of permeability when more than one phase is flowing. To circumvent this problem, pressures can be monitored at an offset well. The well should be located close enough to the injector to show pressure response in a reasonable period of time, but not so close as to be invaded by the injected fluid prematurely.

An offset observation well located 11.5 M from the injector was selected, and its pressure response was monitored during both the water injection and gas injection runs. The results are presented in Figure G-3. The offset pressure response in the case of water injection yields a permeability value of 9.326E-05 UM2, compared to an input value of 9.869E-05. This represents a very good correspondence. For the case of gas injection, the offset pressure response, while still yielding a permeability within 13% of the input value, is a distinctly less reliable measure of this formation characteristic.

The foregoing analysis of offset pressure response to gas injection utilizes an approach which assumes a constant bottomhole rate. However, the boundary condition imposed in the gas injection model run corresponds to a constant surface rate. Accordingly, as bottomhole injection pressure increases, bottomhole rate decreases. This accounts for the reduced slope of the pressure response to gas injection illustrated in Figure G-3. This distortion in pressure response due to a gradually varying rate can be corrected using a simple procedure referred to as normalization[2]. The normalization procedure, which was initially developed to cope with varying production rates at gas wells, is outlined below.

c) Normalization Procedure

Normalization is a simple procedure which permits a pressure response, measured while injection or production rates are gradually varying, to be adjusted so that it represents the pressure response which would have been obtained had the rate been held constant. It has seen its most frequent practical applications where gas is involved, but is not limited to any particular fluid.

If a gradually varying flow rate, q(t), results in a pressure response p(t), then a normalized pressure response, $p_n(t)$, corresponding to a constant rate q_c, can be calculated as follows:

$$(p_i - p(t))/q(t) = (p_i - p_n(t))/q_c \qquad \text{(G-1)}$$

so that

$$p_n(t) = p_i + (q_c/q(t))*(p(t)-p_i) \qquad (G\text{-}2)$$

The resulting normalized pressure values, $p_n(t)$, together with the selected constant rate, q_c, are then used in the appropriate flow equations.

In the foregoing gas injection case, given the bottomhole injection pressure (Figure G-2) and the relationship between gas volume and pressure (Table G-2), the offset well pressure response was normalized using equation G-2. The constant rate, q_c, selected for the normalization was 0.05 M3/D, which corresponds to the bottomhole rate at 1000 kPa.

The results of this normalization are presented, along with the unadjusted pressure response, in Figure G-4. The normalization calculation is summarized in Table G-3. As illustrated in Figure G-4, normalization brings the offset well pressure response during gas injection into close correspondence with the response during water injection. The permeability calculated using the normalized offset well slope differs from the model input value by 6.3%.

d) Effect of Offset Well Distance

In discussing the need for a suitably located offset well, it was noted that it must be close enough to the injector to respond to the pressure disturbance, but far enough away to escape the distorting effects of gas invasion. Table G-4 summarizes the results of locating the offset well at various distances from the gas injector. Injection was at a rate of 0.5 M3/D at standard conditions for 20 days.

As indicated, calculated permeability corresponds more closely to the input value as inter-well distance increases. This reflects the reduced influence of gas invasion at greater radii. In practice, this benefit must be weighed against the reduced magnitude of pressure response measured at the greater distances.

Table G-4 also compares values of $k/\phi\mu c$ calculated from the basic flow equation. Again, the benefit of a larger inter-well distance is indicated. Calculation of $k/\phi\mu c$ will be discussed further in Section H.

e) Effect of Relative Permeability

Gas injection was simulated under horizontal flow conditions for a number of different relative permeability curves, and permeability was calculated from the slope of each offset well pressure response.

Figure G-5 illustrates the offset well pressure responses for two different sets of permeability curves. The relative permeability curves are presented in Figures G-6 and G-7. As shown, despite significant differences in the two sets of curves, the offset well pressure responses (normalized) are nearly identical. Correspondingly, calculated permeability is the same in both cases.

A further illustration is provided in Figure G-8, which shows a close correspondence between calculated and input permeability for a case in which hyperbolic relative permeability curves were used.

The effect of altering relative permeability end-points is illustrated in Figure G-9. A discrepancy of 4.4% between calculated and input values of permeability indicates that the result is not sensitive to the change in end-points.

These results strongly indicate that normalized pressure response at the offset well is largely independent of the relative permeability characteristics in the multi-phase flow region. This finding is very important, as it confirms that, provided offset pressure data are monitored, a knowledge of characteristics in the multi-phase flow region around the injection wellbore is not required.

4. SHUT-IN WELL TEST - HORIZONTAL FLOW

As discussed previously, when a pressure disturbance propagates outward from the injector, it moves much more rapidly than the fluid-fluid interface. This provides an opportunity to monitor a significant portion of the pressure response in the single-phase flow region of the reservoir. However, if the injector is subsequently shut in, a new pressure disturbance is propagated. This disturbance will move initially through the multi-phase fluid region and, depending on the extent of that region (i.e., depending on the amount of injection preceding the shut-in), may be heavily influenced by it.

This is illustrated in Figure G-10, which presents a Horner[3] plot of pressure fall-off following 30 days of gas injection. Attempts to use fall-off data from either the injector or the offset well to calculate permeability resulted in poor correspondence with the input value. Offset pressure data during injection (i.e., charge-up), as expected, yielded a reliable value of permeability.

These results suggest that shut-in pressure data following gas injection into an oil sand are not as likely to be amenable to analysis as the pressure data during the injection period.

H. SINGLE-PHASE VERTICAL WELL TEST ANALYSIS TECHNIQUES

1. RESERVOIR CONFIGURATIONS ASSUMED IN ANALYSIS TECHNIQUES

Currently, there are two types of well test analysis technique for determining vertical permeability.

The first type is embodied in the approach of Prats[4]. The reservoir is assumed to be infinite-acting, uniform, and globally isotropic or anisotropic with respect to permeability. That is, although horizontal permeability may differ from vertical permeability, each is constant throughout the system. This configuration might represent a system in which impediments to vertical flow, such as localized shale/silt lenses, are more or less uniformly distributed throughout the formation.

The second type is dealt with in the approach of Ehlig-Economides and Ayoub[5]. The infinite-acting reservoir is assumed to consist of an upper and a lower zone separated by a layer whose permeability is distinctly lower than that of the others. In both the upper and lower zones, properties such as permeability, porosity and thickness are assumed constant. However, the properties of the upper zone may differ from those of the lower zone. In this representation, each layer or zone is isotropic, so that vertical and horizontal permeability are the same. The effective anisotropy is created by the presence of the intervening low permeability layer, which may impede flow between the upper and lower zones.

The basic elements of each technique are described below.

2. PRATS ANALYSIS TECHNIQUE

a) General Approach

The Prats technique utilizes a single well completed over two intervals which are vertically separated and hydraulically isolated, as illustrated in Figure H-1. The technique assumes single-phase flow, and may involve either production or injection. Since the focus of this study is on injection for reasons already discussed, the testing technique will be described in these terms.

The basic approach involves injecting into the well at a constant rate opposite the injection interval and observing pressure response at the other set of perforations (same-well observation interval). From the slope of the appropriately plotted pressure response, horizontal permeability may be calculated. From the intercept of the pressure response, together with the slope, vertical permeability may be calculated. However, this latter step requires a knowledge of the values of certain other reservoir parameters. The positions of the injection and same-well observation intervals are reflected in the calculation of vertical permeability by means of a single geometric term provided in graphical form by Prats.

b) Well Test Procedure

Following is a summary of the well test procedure:

1) Perforate the well over two intervals, each of which is relatively restricted in length. The two intervals should be separated from each other vertically by a significant interval.

2) Isolate the two sets of perforations by means of tubing and a packer.

3) Inject indigenous formation liquid through the perforations at z' (see Figure H-1) and record pressures at z.

4) Perform the analysis procedure, as summarized below.

c) Well Test Analysis Procedure

1) Plot pressure rise at the observation point versus logarithm of time. An example of the plotting procedure is presented in Figure H-2.

2) From the straight line portion of the plot, determine the slope per logarithmic cycle, m.

3) Extrapolate the straight line portion to a time of 1 hour, and note the pressure drop, $delp_1$.

4) Determine the geometry factor, F, from Prats[4] Figure 2. This factor is a function of the relative vertical positions of the injection (z'/h) and observation (z/h) intervals.

5) Obtain values of ϕ (fraction), μ (mPa.S), c (kPa^{-1}) and h (M).

6) Calculate vertical permeability, k_v (μM^2), as follows:

$$k_v = 277.44\ \phi\mu ch^2 * \exp[(2.303*delp_1/m) - F(z/h,z'/h)] \quad (H-1)$$

7) Calculate horizontal permeability, k_h (μM^2), as follows:

$$k_h = 2.121\ \mu q/(mh) \quad (H-2)$$

3. EHLIG-ECONOMIDES & AYOUB (EE&A) TECHNIQUE

a) General Approach

The EE&A technique, like that of Prats, utilizes a single well completed over two intervals which are vertically separated and hydraulically isolated. Specifically, since a low permeability layer is assumed to intervene between the upper and lower zones, the two perforated intervals are located in opposite sides of the layer. This is illustrated schematically in Figure H-3.

The technique assumes single phase flow, with fluid movement strictly horizontal (and unsteady state) in the permeable zones and strictly vertical (and pseudo-steady state) in the low permeability layer. Storage in the low permeability layer is assumed to be negligible.

The basic approach involves injecting into the well at a constant rate opposite the injection interval and recording pressure response at the same-well observation interval. The pressure response is plotted in an appropriate manner, as described subsequently, and is compared with a family of type curves. Based on the selection of an appropriately matching type curve, vertical permeability is calculated.

The principle objective of the EE&A analysis technique is to determine vertical permeability. In addition, however, the EE&A technique permits calculation of both skin and wellbore storage effects. The variation in these factors accounts for the multiplicity of type curves. In this study, however, wellbore storage was neglected. Whereas the EE&A technique, as presented by its authors, provides procedures for extracting information on

wellbore storage and other reservoir parameters from early-time pressure response, it was assumed in this study that early time data was likely to be unreliable and therefore not a valid source of pressure response information. Based on these constraints, and considering a typical range of reservoir conditions in a virgin oil sand, it was possible to select the limiting type curve for use in this study. This curve, which plots dimensionless pressure versus a dimensionless time group in log-log form, is illustrated in Figure H-4.

b) Well Test Procedure

Following is a summary of the well test procedure:

1) Perforate the well so that there is an open interval on each side of the low permeability layer.

2) Isolate the two intervals hydraulically from each other by means of tubing and a packer.

3) Inject indigenous formation liquid at a constant rate through one set of perforations and record pressure at both sets.

4) Perform the analysis procedure as summarized below.

c) Well Test Analysis Procedure

As noted above, the EE&A technique, as applied in this study, assumed that wellbore storage effects were negligible. It also assumed that, whereas the technique permits the determination of individual zone permeabilities from early-time data, this might not be feasible in practice. Nevertheless, the analysis procedure which is described below includes the calculation of individual zone permeabilities from early time data for the sake of completeness.

1) Prepare a log-log plot of pressure rise at the observation point versus time.

2) Attempt to determine k_1 from a type curve match of the early pressure response [log(delp$_1$) vs log(time)] opposite the injection/production interval:

$$k_1 = 1.842\ q\mu(p_D)_M/[(delp_1)_M * h_1] \qquad (H\text{-}3)$$

3) From the later time portion of the pressure response (determined by establishing that p_2-p_1 is constant), determine the total permeability-thickness by plotting either p_1 or p_2 vs log(time) and calculating as follows:

$$k_1h_1 + k_2h_2 = 2.121\ q\mu/m \qquad \text{(H-4)}$$

4) From the results of steps 1 and 2, calculate k_2.

5) Match the later time portion of the p_2 pressure response [log($delp_2$) vs log(time)] against the type curve.

6) From the match of the ordinate values, note the corresponding values of dimensionless pressure drop, p_{2D}, and measured pressure drop, $delp_2$, and calculate

$$k_1h_1 + k_2h_2 = 1.842\ q\mu(p_{2D})_M/[(delp_2)_M] \qquad \text{(H-5)}$$

7) From the abscissa of the type curve match, note the dimensionless $(Bt_{DV})_M$ and actual (t_M) time values. Calculate vertical permeability, k_v, as follows:

i) Obtain values of ϕ and c for each of the two zones and calculate:

$$R = (\phi ch)_1 + (\phi ch)_2$$
$$Y = k_1h_1 + k_2h_2$$

ii) Obtain value for thickness of tight layer, delh.

iii) Calculate $T = [(1/(k_1h_1)) + (1/(k_2h_2))]$

iv) Calculate k_v as follows:

$$k_v = (46.274*(Bt_{DV})_M*delh*\mu/t_M)*(R/(Y*T)) \qquad \text{(H-6)}$$

4. DISCUSSION OF PRATS AND EE&A TECHNIQUES

Both the Prats and EE&A well test analysis techniques require a knowledge of the porosity and compressibility. However, accurate compressibility information is often not available. Also, in the specific case of oil sand, it is unlikely that the effective porosity (i.e., the fraction of pore space occupied by mobile

water) will be known. Accordingly, in their traditional form, these two methods, while theoretically sound, may not be practical.

A further difficulty in the case of the EE&A technique pertains to type curve matching. Superposition of measured pressure response data upon the type curve is often not without some ambiguity. A relatively small discrepancy in alignment of the curves can translate into a significant error in the subsequent calculation of vertical permeability.

The subsequent discussion of these two methods describes their modification to accomodate gas injection into an oil sand. In the course of developing those modifications, procedures have also been created to deal with both of the foregoing limitations of the traditional approaches.

Accordingly, to the extent that the subsequent treatment of the Prats and EE&A techniques includes a number of modifications, some of these represent adaptations specifically to account for gas injection, while others are changes to the basic method.

I. SINGLE-PHASE FLOW - MODIFICATIONS TO PRATS TECHNIQUE

1. GENERAL

As noted above, both the Prats and EE&A techniques require a knowledge of parameters such as effective porosity, 0, and compressibility, c. A reliable value of compressibility is often not available and, in an oil sand, where the effective pore space is some unknown portion of the water phase, effective porosity is also not defined.

An alternative approach is to calculated the 0c term from data obtained during the well test. In the case of the Prats technique, as applied to single phase flow, it is theoretically possible to determine the 0c term from pressure response at the injection interval, provided the skin term is known. In practice, however, this is not known a priori. In fact, well test analysis techniques usually rely on some estimate of 0c so that the skin term (i.e., the degree of wellbore damage or improvement) can be determined.

If pressure response data can be obtained at an offset observation well in a manner such that they reflect only the horizontal component of flow, those pressures will not be affected by either the skin term at the injection/production well or the vertical permeability in the reservoir. It will then be feasible to calculate the 0c term. Inasmuch as the type of well test prescribed in this study for two-phase flow requires that pressures be measured at an offset well, this extra set of pressures provides a means of accomplishing this. The relevant single-phase flow equations are presented below.

2. CALCULATION OF ∅c TERM

Once the straight-line portion of the pressure response at the offset well (i.e., pressure vs log(time)) has developed, the following equation applies:

$$delp = 1.8423*(q\mu/(k_h h))*[0.5*(\ln(t_D) + 0.809)] \qquad (I\text{-}1)$$

where

$$t_D = 0.08640*kt/(\phi\mu c r^2) \qquad (I\text{-}2)$$

Equation (I-1) can be expressed as follows:

$$(k_h/(\phi\mu c) = 5.154*(r^2/t)*\exp[2.303(delp/m)] \qquad (I\text{-}3)$$

Equation (I-3) indicates that if the slope of the straight-line portion of the offset pressure response curve, m, is determined, then an offset pressure response (delp) can be selected at some time, t. Inputting these values into equation (I-3), along with the distance from injector to offset, r, the term $k_h/\phi\mu c$ can be calculated.

The horizontal transmissibility, $k_h h/\mu$, is related to the slope, m, as follows:

$$k_h h/\mu = 2.121 * q/m \qquad (I\text{-}4)$$

Substituting equation (I-4) into (I-3) and re-arranging,

$$\phi c = 0.4115*(q/mh)*[(r^2/t)*\exp(2.303*delp/m)] \qquad (I\text{-}5)$$

3. CALCULATION OF k_v/k_h RATIO

Equation (I-5) provides a means of calculating the ϕc term. However, as illustrated below, the development can be extended one step further to determine the ratio of vertical to horizontal permeability, k_v/k_h.

Earlier, equation (H-1) was presented. It calculates vertical permeability, based on the pressure response at the same-well observation point as follows:

$$k_v = 277.44*\phi\mu c h^2 * \exp[(2.303*delp_1/m) - F] \qquad (H\text{-}1)$$

where $delp_1$ is obtained by extrapolation of the straight-line portion of the same-well pressure vs log(time) plot to a time of one hour.

Combining equations (H-1) and (I-3),

$$k_v/k_h = 53.85 * t * (h/r)^2 * E \qquad (I-6)$$

where

$$E = \{\exp[2.303*(delp_1/m)-F]/\exp[2.303*(delp/m)]\} \qquad (I-7)$$

Equation (I-7) can be further simplified as follows:

$$E = \exp[(2.303/m)*(delp_1-delp) - F] \qquad (I-8)$$

In equations (I-6) through (I-8), t is in days. All other units need only be consistent.

It is important to note that the terms $delp_1$ and delp refer to different observation points. The term $delp_1$ refers to the same-well observation point, whereas delp refers to the offset observation well. Also, $delp_1$ is the pressure change (from original) after one hour of injection. On the other hand, delp represents a pressure change after a selected time, t days.

4. DETERMINATION OF PRESSURE RESPONSE AT THE OFFSET WELL

The foregoing discussion presents an improved method of calculating k_v/k_h based on the assumption that pressure response data are recorded at an offset observation well. Furthermore, the equations presented above for calculating Øc from offset observation well data are based on horizontal flow. However, at any given time, pressure at the observation well location will vary as a function of vertical position. That is, if the offset well is perforated over, say, two separate intervals, each interval will exhibit a distinctive pressure because flow is not exclusively horizontal. Accordingly, a technique which relies on offset well response will require a precise definition of pressure at this location.

Figure I-1 illustrates pressure response at an offset well in a single-phase flow system with both horizontal and vertical flow. In response to water injection at a rate of 0.05 M^3/D over a restricted interval into a reservoir initially at 1000 kPa, three pressure responses at a distance of 11.5 M from the injector are plotted. One response is the pressure at mid-formation as calculated by the numerical model. A second response is calculated from the analytic expression for single phase strictly horizontal flow. It is obvious that the mid-formation pressure response is not representative of the pressure which would occur if flow were horizontal. Accordingly, the mid-formation pressure response could not be used in the foregoing equations to provide a reliable value for delp. The third curve presents the vertically-averaged pressure at the offset well location. Since the model layers were all of equal thickness (15 layers, each 1.0 M in thickness), the vertically-averaged pressure was calculated by averaging the 15 layer pressures arithmetically. It is apparent that the resulting average corresponds closely with the analytic pressure response.

These results suggest that, to determine pressure response at the offset well for use in the foregoing equations, an average value is required. In the case of the modified Prats technique, the arithmetic average is suitable. However, as will be illustrated later in discussing the EE&A technique, another type of average pressure is required in certain situations. To accomodate this, it becomes necessary to measure offset well pressure over more than one interval in the well. Because of practical limitations, it may be difficult to record pressure responses over a large number of distinctive intervals. However, results discussed subsequently in relation to the EE&A technique suggest that offset pressures measured at two vertically distinctive locations within the well will suffice.

5. MODIFIED PRATS ANALYSIS TECHNIQUE - SINGLE-PHASE FLOW

Table I-1 illustrates the calculation of k_v/k_h in a single-phase water injection regime for two different reservoir conditions. In the first, the reservoir is isotropic, so that horizontal and vertical permeability are identical. In the second, vertical permeability is 10% of horizontal permeability.

The upper panel of Table I-1 presents salient input data. The middle panel compares input values of the horizontal diffusivity term, $k_h/(\phi\mu c)$, with those calculated using the modified technique. And the third panel summarizes the results of k_v/k_h calculations.

Referring to the middle panel, note that calculated horizontal diffusivity, which includes the ϕc term referred to earlier, differs significantly from the input value for both the isotropic and anisotropic cases. Since the ϕc term is used, at least implicitly, in determining k_v/k_h, this appears to present a problem. In fact, however, there appears to be a self-compensating aspect of the k_v/k_h calculation, so that this apparent discrepancy is not conveyed into the final result. This is illustrated subsequently.

The bottom panel of Table I-1 presents the calculation results. Note that k_v/k_h has been calculated using both the input value of diffusivity, $k_h/(\phi\mu c)$, and the value determined from the offset well pressure response.

Referring to the isotropic case, the value of k_v/k_h calculated using the input diffusivity is 0.654, compared with the actual value of 1.00. This is a 34.6% discrepancy. If, however, diffusivity is determined from offset pressure response, the calculated value of k_v/k_h is 0.979, which differs from the input value by only 2.1%.

Similarly, for the anisotropic case, using the input value of diffusivity results in an 18.2% discrepancy in k_v/k_h, whereas the diffusivity value determined from offset pressure response creates a discrepancy of only 6.0%.

6. SUMMARY OF MODIFICATIONS TO PRATS TECHNIQUE

The foregoing discussion demonstrates that, with the aid of pressure response data from an offset observation well, together with the same-well observation data, the vertical-to-horizontal permeability ratio can be calculated without the need for any assumptions regarding porosity and compressibility.

Indeed, as equations (I-6) and (I-8) demonstrate, it is not even necessary to know the viscosity of the fluid.

To achieve this result, a valid set of offset well pressure response data must be determined. For a homogeneous reservoir, whether isotropic or anisotropic, offset pressures are calculated by arithmetically averaging individually recorded pressures at a series of vertical locations which are uniformly distributed and hydraulically isolated.

In summary, the need for an offset observation well during two-phase flow, to provide pressure response data in the non-invaded zone, leads to a technically improved version of the Prats technique, both for single-phase and two-phase flow. The modified technique permits the user to calculate k_v/k_h with fewer assumptions than the original technique requires.

J. MODIFIED PRATS TECHNIQUE - TWO PHASE FLOW

1. GENERAL

This section describes the Prats well test procedure and analysis technique, modified for two-phase flow. As such, it incorporates results described in Section G relating to two-phase flow, as well as findings presented in Section I which pertained to both single-phase and two-phase flow.

In addition, one refinement in calculating the slope, m, as discussed below, is also included as part of the modified Prats technique.

2. SYNTHESIZED SAME-WELL SLOPE

As described in Section I, calculation of k_v/k_h ratio relies on pressure response data from both the offset observation well (delp) and the same-well observation point ($delp_1$).

The two-phase flow regime resulting from gas injection into a virgin oil sand can cause some distortion in pressure response. However, in the case of the offset well, its distance from the injector and the pressure-averaging technique used to calculated pressure response will mitigate this distortion. At the same-well observation point, on the other hand, this distortion may lessen the accuracy of the final result.

This is illustrated in Figure J-1, where one of the two curves shown represents the measured pressure response at the same-well observation point. Since gas injection is involved, all pressure responses must first be normalized to account for varying bottomhole rate. Accordingly, the pressure response presented in Figure J-1 has already been normalized. When the slope of this curve is used to calculate k_v/k_h, the resulting value is 0.0878, compared with an input value of 0.1000. Although this represents a relatively good correspondence, it can be improved as follows. Assuming that the slope of the pressure response at the offset observation well is less distorted than that of the same-well observation point, it can be selected as more accurate. The same-well observation data can then be modified so that its slope is identical to that of the offset well. This can be accomplished by

selecting an early-time point on the same-well observation response curve. The point is selected so that it is at or near the beginning of the straight-line portion of the curve, prior to any significant distortion by gas injection. A new same-well curve can then be constructed using this selected point and the slope from the offset well. This is illustrated in Figure J-1. When the slope from this synthesized curve is used, the resulting value of k_v/k_h is 0.0997, which corresponds very closely with the input value. This result is also summarized in Table J-1.

The foregoing procedure is again illustrated in Figure J-2, which plots the same-well pressure response for gas injection into an isotropic reservoir. A point on the curve is selected corresponding to inception of the straight-line portion of the plot. Using this point, and the slope of 76.33 kPa determined from the normalized pressure response at the offset well, a new same-well pressure response curve is synthesized. This is shown as a straight-line plot in Figure J-2. Also illustrated is the extrapolation of the synthesized curve to obtain the value of $delp_1$ required in the calculation of k_v/k_h. The results are further summarized in Table J-2. If the original same-well observation data had been used to determine the slope, m, this would have yielded a k_v/k_h value of 0.854, compared with the input value of 1.000. By utilizing the offset well slope along with an early-time point from the straight-line portion of the same-well data, a value of 0.895 was determined.

3. INFLUENCE OF HYDROSTATIC GRADIENT (HEAD)

Neither the Prats nor EE&A technique deals explicitly with the hydrostatic gradient (head) which must be included when there are significant vertical distances involved.

To ensure that valid results are obtained, pressures should be corrected to a common vertical datum, such as mid-formation depth. The influence of head, and the results obtained when pressures are corrected are illustrated in Figures J-3 and J-4.

Figure J-3 presents normalized pressure response at the same-well observation point during gas injection. Pressure response is shown for both isotropic and anisotropic reservoirs. Two of the four curves represent pressure response in a system where the head effect is zero (i.e., the fluids have zero density). The other two curves reflect a system in which there is a hydrostatic gradient, but where a correction to mid-formation datum has been applied. Note that for the isotropic reservoir, the head-corrected pressure

deviates significantly at late times from the zero-head response. This reflects the rapid vertical movement of gas towards the same-well observation interval, with a consequent distortion in corrected pressure. On the other hand, in the anisotropic reservoir, injected gas does not migrate as readily toward the same-well observation interval. As a consequence, there is much less distortion, and the head-corrected pressure corresponds very closely with the pressure when there is no head.

Figure J-4 presents the analogous result for pressures measured at the offset observation well. Note that, irrespective of whether the reservoir permeability is isotropic or anisotropic, there is a close correspondence between pressures in a system with no head and depth-adjusted pressures when head is present. Accordingly, Figure J-4 illustrates the validity of the head adjustment to mid-formation depth. In addition, comparison of Figures J-3 and J-4 supports the concept of utilizing the offset well pressure data to determine slope, m, and pressure response $delp_1$, while restricting the use of same-well pressure data to selection of an early time point on its straight-line segment for use in determining $delp_1$.

4. SUMMARY OF MODIFIED PRATS TECHNIQUE

a) Summary of Modifications

The modified Prats technique, which is outlined subsequently, includes the following features:

1) Bottomhole pressure data are gathered at several locations. These include the same-well observation interval, each interval at the offset observation well, and the injection perforations.

2) Injection rate is monitored on a continuous basis.

3) Pressures are corrected for hydrostatic gradient (head) to a suitable datum, such as mid-formation depth.

4) Datum-corrected pressure response data (both same-well and offset observation well) are normalized to account for gradually varying bottomhole rate.

5) The same-well observation pressure response is re-synthesized using an early time portion from its straight-line

segment together with the slope from the offset observation well pressure response.

6) In calculating k_v/k_h, required porosity and compressibility data are generated from within the well test (i.e., from the offset well pressure response) rather than externally.

b) Summary of Field Test Procedure

1) Utilize two wells. These wells will be cased through and perforated so that zones may be hydraulically isolated. One well will include two sets of perforations which are isolated from each other and which are separated by a significant vertical interval. At one of these intervals, gas will be injected, and instantaneous rate and pressures monitored and recorded. At the other (i.e., the same-well observation point), pressures will be monitored and recorded. The second well is located at a selected distance from the first, and is completed with two or more perforated intervals which more or less uniformly span the zone of interest and which are capable of mutual isolation, so that pressures may be individually monitored and recorded. Selection of this offset distance will be based on estimates of fluid interface and pressure transient advances. The offset well should be close enough to detect significant pressure response, but far enough to be largely beyond the region of major gas invasion.

2) Inject gas, monitor instantaneous rate, and observe pressure response at the injection perforations. Ideally, gas injection should be at a constant bottomhole rate. In practice, however, this is unnecessary. The surface conditions need only be sufficiently steady to ensure that bottomhole rates are not varying rapidly. For example, if either constant surface rate or a constant surface pressure is maintained, this will usually result in a gradually changing bottomhole rate whose variation can be accounted for through normalization.

3) Monitor and record pressure response at the same-well observation perforations.

4) Monitor and record pressure response opposite each of the offset well intervals.

c) Summary of Well Test Analysis Procedure

1) Correct all pressures to a common datum, such as mid-formation depth.

2) Using the pressure data at the injection interval, together with the recorded surface rate data, normalize the pressures recorded at both the same-well and offset-well locations. Table G-3 presents an example in which offset well pressure is adjusted through normalization. This process involves adjustment of bottomhole pressures, which are responding to a varying rate, in such a manner that that they represent the response which would have occurred at some selected constant bottomhole rate q_c. The normalization equation is as follows:

$$p_n(t) = p_i + (q_c/q(t))*(p(t)-p_i)$$

Further references to same-well and offset-well pressures will refer to normalized pressures.

3) From the charge-up period data, plot pressure rise at the offset observation point versus logarithm of time.

4) From the straight-line portion of the plot, determine the offset well slope per cycle, m.

5) Repeat steps 1 and 2 for the same-well pressure data, and determine a same-well slope per cycle, m_s.

6) Compare the two slopes, m and m_s. In general, if there is any significant difference between these slopes, the offset slope, m, is likely to be the more reliable. Accordingly, it should be selected for use in subsequent calculations.

7) Assuming the slope, m, is selected, then re-synthesize the same-well pressure data such that it too has the slope, m. This is done as follows:

i) From the same-well pressure data, select the earliest-time point which appears to form part of the straight line trend.

ii) Using this pressure value, and the slope m, calculate new same-well pressure values at each time.

8) From the offset slope, m, calculate horizontal permeability, k_h, as follows:

$$k_h = 2.121\ \mu q_c/(mh)$$

where q_c is defined in step 2) above. This step is optional, inasmuch as it is not required in calculating k_v/k_h. However, it is advisable to carry out the calculation, since all such results should be checked for reasonableness.

9) Using the offset pressure data at a selected time, the diffusivity term may be calculated as follows:

$$k_h/(\phi\mu c) = 5.154*(r^2/t)*\exp(2.303*delp/m)$$

where delp is the difference between the (normalized) pressure and the initial reservoir pressure, p_i. That is,

$$delp = p(r,t) - p_i,$$

where p(r,t) is the instantaneous pressure at time t and at a horizontal distance r from the injector (i.e., the distance from injector to offset well).

Calculation of $k_h/(\phi\mu c)$ is optional. Although the value of delp, along with the corresponding values of r and t are required in calculating k_v/k_h, as described below, the explicit calculation of $k_h/(\phi\mu c)$ is not required. However, for purposes of information, its calculation is recommended.

10) Using the straight-line portion of the (synthesized) same-well pressure data, determine $delp_1$, the pressure rise above original reservoir pressure after one hour. Since $delp_1$ is a mathematical construct obtained by extrapolating the straight-line portion backward in time into a region where, physically, no straight line portion existed, its value may actually be negative.

11) Determine the geometry factor, F, from Prats[4] Figure 2. This is a function of the relative vertical positions of the injection (z'/h) and same-well observation (z/h) intervals.

Some values of F commonly used in this study are as follows:

h, M	z', M	z, M	F
15.0	14.5	0.5	1.973
15.0	11.5	2.5	2.367

12) Calculate vertical-to-horizontal permeability ratio as follows:

$$k_v/k_h = 53.85 * t*(h/r)^2 * E$$

where

$$E = \exp[(2.303/m)*(delp_1 - delp) - F].$$

K. MODIFIED EE&A TECHNIQUE - SINGLE & TWO-PHASE FLOW

1. SINGLE-PHASE FLOW - MODIFICATIONS TO EE&A TECHNIQUE

Figure H-3 illustrated schematically the configuration of perforated intervals in the situation where a low permeability layer is interposed between the upper and lower zones. Since it reflects the traditional EE&A technique, only a single well is represented. Figure K-1 expands this schematic to include the offset observation well which is required for two-phase flow, and which can be used to improve the single-phase flow technique. Note that, for the specific case shown, there are two distinct pressure observation intervals at the offset well. It is important that these be located on each side of the low permeability layer, so that the offset pressure in each zone is measured individually.

Several of the modifications which pertain to the single-phase flow version of the Prats analysis also apply to the single-phase flow version of EE&A. In addition, the EE&A single-phase analysis technique can itself be modified to improve the accuracy of the type curve matching procedure by using data which are already available.

These single-phase modifications are described below:

1) Adjust all pressures for hydrostatic gradient (head).

2) Calculate the offset well pressure response by an appropriate averaging of the pressures measured in each of the two zones. As will be discussed later, the following guidelines for calculation of average offset pressure apply:

i) If injection occurs in the less permeable zone, an arithmetically averaged offset pressure is calculated (assuming that porosity is similar in both zones).

ii) If injection occurs in the more permeable zone, a transmissibility-weighted average offset pressure is calculated.

3) Utilize the offset pressure data to determine k_h and ϕc. The ϕc value calculated in this manner can be multiplied by formation thickness, h, to obtain ϕch, and this can be substituted for the term $[(\phi ch)_1+(\phi ch)_2]$ in the EE&A calculation.

4) Improve the type-curve matching technique by using available data to partially force the fit. The EE&A technique for single-phase flow can be modified to allow for an improved fit of the same-well observation pressure data along the type curve. As described by the authors, the EE&A method requires the curve fit so that horizontal flow characteristics can then be calculated from the ordinate and vertical flow characteristics from the abscissa. Given the uncertainty in achieving an accurate curve fit, it is more desirable to be able to fix one of the two coordinates and calculate the other. This option is inherently available and the corresponding procedure is described below:

i) Plot the offset well observation pressure data in the same manner as described in the Prats analysis technique (i.e., pressure vs log(time)).

ii) From the slope, m, calculate the total system transmissibility, $(k_h h)_t$. In effect,

$$(k_h h)_t = k_1 h_1 + k_2 h_2 = 2.121\ q\mu/m \qquad (K\text{-}1)$$

iii) Reverse equation H-5 to calculate the relationship between the ordinate on the type curve and the corresponding measured value of pressure, as follows:

$$(p_{2D})_M/[delp_2)_M] = (k_1 h_1 + k_2 h_2)/(1.842\ q\mu) \qquad (K\text{-}2)$$

Equations (K-1) and (K-2) can be simplified as follows:

$$(p_{2D})_M/[delp_2)_M] = 1.1515/m \qquad (K\text{-}3)$$

Accordingly, from the slope at the offset well, the ordinate ratio can be calculated using equation (K-3).

iv) Plot the same-well pressure response on log-log coordinates so that it can overlay the type curve. Force the ordinate of the pressure data to correspond to the ordinate of the type curve in accordance with the calculation using equation (K-3).

v) Translate the plot horizontally (i.e., adjust the abscissa only) to obtain the best overall fit. From the resulting

abscissa values calculate vertical permeability using equation (H-6).

5) Estimate individual zone transmissibilities. Application of equation (H-6) also requires a knowledge of the individual zone transmissibilities, k_1h_1 and k_2h_2. Although the EE&A technique describes a method for determining this using early time data, it is not clear that this will be generally feasible. An alternative approach is to use core analysis to determine the ratio of transmissibilities, k_1h_1/k_2h_2, and then use the total transmissibility calculated in equation (K-1) to determine the individual zone values.

2. TWO-PHASE FLOW - MODIFICATIONS TO EE&A TECHNIQUE

The foregoing modifications to the EE&A technique can also be utilized in two-phase flow applications. In addition, modifications are needed specifically to accomodate two-phase flow. These are identical to the modifications enumerated for the modified Prats technique, and include:

1) Normalization of all pressure data to adjust for varying bottomhole flow rate.

2) Synthesis of a same-well pressure curve using a point from the early-time portion of the same-well data together with the slope, m, from the offset well pressure response.

3. SUMMARY OF MODIFIED EE&A TECHNIQUE

a) Summary of Modifications

The modified EE&A technique, which is outlined subsequently, includes the following features:

1) Bottomhole pressure data are gathered at several locations. These include the same-well observation interval, each interval at the offset observation well, and the injection perforations.

2) Instantaneous injection rate data are recorded.

3) Pressures are corrected for hydrostatic gradient (head) to a suitable datum, such as mid-formation depth.

4) Datum-corrected pressure response data (both same-well and offset observation well) are normalized to account for gradually varying bottomhole rate.

5) Offset well pressure responses at each of the perforated intervals are averaged. The method of averaging depends on whether gas is injected into the lower or higher quality zone.

6) The same-well observation pressure response is re-synthesized using an early time portion from its straight-line segment, together with the slope from the offset observation well.

7) Offset pressure data are used to calculate total transmissibility, from which individual zone values can be estimated.

8) Offset pressure data are used to calculate ϕch.

9) Offset pressure data are used to fix the relationship between the ordinate of the type curve and the ordinate of the same-well pressure response.

10) The ordinate fit is forced, and the same-well observation pressure response is translated horizontally to obtain a fit of the abscissa. From this fit, k_v/k_h is calculated.

b) Summary of Field Test Procedure

1) Utilize two wells. These wells will be cased through and perforated so that zones may be hydraulically isolated. The injection well will include two sets of perforations which are isolated from each other and which are separated by a significant vertical interval. At one of these intervals, gas will be injected, and instantaneous rates and pressures monitored and recorded. At the other (i.e., the same-well observation point), pressures will be monitored and recorded. The second well is located at a selected distance from the first, and is completed with two or more perforated intervals which more or less uniformly span the zone of interest and which are capable of mutual isolation, so that pressures may be individually monitored and recorded. Specifically, at the offset well, there must be perforated intervals both above and below the low permeability layer. Selection of the offset well distance will be based on estimates of fluid interface and pressure

transient advances. The offset well should be close enough to detect significant pressure response, but far enough to be largely beyond the region of major gas invasion.

2) Inject gas and monitor instantaneous rate and pressure response at the injection perforations. Ideally, gas injection should be at a constant bottomhole rate. In practice, however, this is unnecessary. The surface conditions need only be sufficiently steady to ensure that bottomhole rates are not varying rapidly. For example, if either constant surface rate or a constant surface pressure is maintained, this will usually result in a gradually changing bottomhole rate whose variation can be accounted for through normalization.

3) Monitor and record pressure response at the same-well observation perforations.

4) Monitor and record pressure response opposite each of the offset well intervals.

c) Summary of Well Test Analysis Procedure

1) Correct all pressures to a common datum, such as mid-formation depth.

2) Using the pressure data at the injection interval, together with the recorded surface rate data, normalize the pressures recorded at both the same-well and offset-well locations. Table G-3 presents an example in which offset well pressure is adjusted through normalization. This process involves adjustment of bottomhole pressures, which are responding to a varying rate, in such a manner that that they represent the response which would have occurred at some selected constant bottomhole rate q_c. The normalization equation is as follows:

$$p_n(t) = p_i + (q_c/q(t))*(p(t)-p_i) \qquad (K-4)$$

Further references to same-well and offset-well pressures will refer to normalized pressures.

3) From the charge-up period data, plot pressure rise at the offset observation point versus logarithm of time.

4) From the straight-line portion of the plot, determine the offset well slope per cycle, m.

5) Repeat steps 1 and 2 for the same-well pressure data, and determine a same-well slope per cycle, m_s.

6) Compare the two slopes, m and m_s. In general, if there is any significant difference between these slopes, the offset slope, m, is likely to be the more reliable. Accordingly, it should be selected for use in subsequent calculations.

7) Assuming the slope, m, is selected, then re-synthesize the same-well pressure data such that it too has the slope, m. This is done as follows:

i) From the same-well pressure data, select the earliest-time point which appears to form part of the straight line trend.

ii) Using this pressure value, and the slope m, calculate new same-well pressure values at each time.

8) From the offset slope, m, calculate average horizontal permeability, k_h, as follows:

$$k_h = 2.121\ \mu q_c/(mh) \qquad \text{(K-5)}$$

where q_c is defined in step 2) above. This step is optional, inasmuch as it is not required in calculating k_v/k_h. However, it is advisable to carry out the calculation, since all such results should be checked for reasonableness.

9) From the slope, m, calculate the total system transmissibility, $(k_h h)_t$. In effect,

$$(k_h h)_t = k_1 h_1 + k_2 h_2 = 2.121\ q_c \mu/m \qquad \text{(K-1)}$$

10) Using the offset pressure data at a selected time, the diffusivity term may be calculated as follows:

$$k_h/(\phi\mu c) = 5.154*(r^2/t)*\exp(2.303*delp/m) \qquad (K\text{-}6)$$

where delp is the difference between the (normalized) pressure and the initial reservoir pressure, p_i. That is,

$$delp = p(r,t) - p_i,$$

where p(r,t) is the instantaneous pressure at time t and at a horizontal distance r from the injector (i.e., the distance from injector to offset well).

Calculation of $k_h/(\phi\mu c)$ is optional. Although the value of delp, along with the corresponding values of r and t are required in calculating k_v/k_h, as described below, the explicit calculation of $k_h/(\phi\mu c)$ is not required. However, for purposes of information, its calculation is recommended.

11) Plot the offset well observation pressure data in the same manner as described in the Prats analysis technique (i.e., pressure vs log(time)).

12) From equations (K-6) and (K-1) calculate average ϕch as follows:

$$\phi ch = (\phi ch)_1+(\phi ch)_2 = 0.4115*(q_c/m)*t/[r_2*\exp(delp/m)] \qquad (K\text{-}7)$$

13) Reverse equation H-5 to calculate the relationship between the ordinate on the type curve and the corresponding measured value of pressure, as follows:

$$(p_{2D})_M/[delp_2)_M] = (k_1h_1 + k_2h_2)/(1.842\ q_c\mu) \qquad (K\text{-}2)$$

Equations (K-1) and (K-2) can be simplified as follows:

$$(p_{2D})_M/[delp_2)_M] = 1.1515/m \qquad (K\text{-}3)$$

Accordingly, from the slope at the offset well, the ordinate ratio can be calculated using equation (K-3).

14) Plot the same-well pressure response on log-log coordinates so that it can overlay the type curve. Force the ordinate of the pressure data to correspond to the ordinate of the type curve in accordance with the calculation using equation (K-3).

15) With the ordinate fixed, translate the plot horizontally (i.e., adjust the abscissa only) to obtain the best overall fit. From the resulting abscissa values calculate vertical permeability using equation (H-6) as follows:

16) From the abscissa of the type curve match, note the dimensionless $(Bt_{DV})_M$ and actual (t_M) time values. Calculate vertical permeability, k_v, as follows:

i) From step 12), $R = (\phi ch)_1 + (\phi ch)_2$

ii) From step 9), $Y = k_1h_1 + k_2h_2$

iii) Obtain value for thickness of tight layer, delh.

iv) From core analysis or logs estimate k_1h_1/k_2h_2

v) Calculate $T = [(1/(k_1h_1)) + (1/(k_2h_2))]$, using results of steps ii) and iv).

vi) Calculate k_v as follows:

$$k_v = (46.274*(Bt_{DV})_M*delh*\mu/t_M)*(R/(Y*T)) \qquad (H-6)$$

L. MODIFIED PRATS ANALYSIS TECHNIQUE - CASES

1. BASE CASES

Tables J-1 and J-2 illustrated the general applicability of the modified Prats technique to two-phase flow. For both an isotropic reservoir, and an anisotropic system in which input k_v/k_h was 0.10, the modified technique yielded reliable values. In these two instances, the reservoir was homogeneous, which is consistent with the basic assumption of the method.

2. DISTANCE TO OFFSET OBSERVATION WELL

Table L-1 illustrates the sensitivity of the method to distance between the injector and the offset well.

For both the isotropic and anisotropic reservoirs, three inter-well distances were examined - 7.0 M, 11.5 M, and 20.0 M.

Note that at a distance of 7.0 M, correspondence between input and calculated values of k_v/k_h is excellent in the case of an isotropic system and quite poor for the anisotropic system. This relates to the pattern of gas invasion. In the isotropic system, injected gas flows more or less spherically outward. In contrast, gas flow in the anisotropic reservoir focuses more strongly in a radial direction, and much less so vertically. As a consequence, gas invasion at the 7.0 M distance is much more pronounced in the anisotropic case, and the resulting distortion in pressure response results in an inaccurate determination of k_v/k_h.

At distances of 11.5 and 20.0 M, correspondence between input and calculated values of k_v/k_h is very good for both isotropic and anisotropic reservoirs. This indicates that, even in the anisotropic case, with its correspondingly more extensive horizontal gas invasion, the offset well is positioned sufficiently far from the injector to mitigate any such adverse effect on the calculated result.

3. RANDOM PERMEABILITY DISTRIBUTION

Reservoir homogeneity is a basic assumption of the Prats technique. However, a case was run to test the robustness of the modified Prats technique by imposing a random variation in permeability within the active flow region of the model.

The result, which is presented in Table L-2, shows a good correspondence overall. The calculated diffusivity value is within 2.0% of the input value. Also, the discrepancy between input and calculated values of k_v/k_h is 9.4%. This close correspondence suggests that the modified Prats technique yields reliable results for the type of random permeability distribution tested.

4. HIGH PERMEABILITY LAYER

A high permeability layer was imposed on an otherwise homogeneous reservoir, as summarized in Table L-3. The layer, with a 1.0 M thickness, was located at mid-formation (i.e., 7.5 M above the base), and was assigned a permeability five times that of the remainder of the reservoir. The system was locally isotropic. Gas was injected 11.5 M above the base of the formation over a 1.0 M interval, and same-well pressures were recorded 2.5 M above the base. The offset observation well was located 11.5 M from the injector.

The resulting determination of k_v/k_h using the modified Prats technique resulted in a discrepancy of 10.0% between input and calculated values.

This result suggests that despite the presence of a high permeability streak, gas invasion at the offset well was not sufficiently advanced to cause any major distortion in the calculated results. However, this conclusion requires some qualification. The injection interval and the high permeability streak were located at different elevations within the reservoir. Had the gas been injected directly into the high permeability streak, it is likely that invasion at the offset well would have been more severe, and calculated results correspondingly poorer. An obvious follow-on conclusion is that, after examination of available reservoir description data, such as logs and/or core, the operator should ensure that the injection interval is not positioned opposite a laterally extensive high permeability streak.

M. MODIFIED EE&A TECHNIQUE - CASES

1. WATER INJECTION

a) General

The cases presented in this sub-section illustrate the application of the modified technique to single-phase flow. At the same time, this section examines the question of calculating average pressure at the offset well from the respective individual zone pressures.

The well and reservoir configuration is illustrated schematically in Figure K-1. To ensure consistency in the following discussions, the upper zone will refer to the zone into which fluid is injected. In practice, of course, either zone could be selected for injection.

Results discussed earlier (see also Table L-1) demonstrated that any one of a range of inter-well distances may be selected in positioning the offset observation well. However, the cases discussed subsequently assume an inter-well distance of 11.5 M.

The positions of the injection and same-well observation intervals were selected to maximize vertical separation. Accordingly, within the 15.0 M thick reservoir, the injection point was located 0.5 M from the top of the formation, and the same-well injection point was situated 0.5 M from the base.

b) Identical Properties in Upper and Lower Zones

Figure M-1 presents the type curve match for a reservoir in which the zones above and below the low permeability streak have identical properties. The low permeability streak is situated at mid-formation. The hydrostatic gradient (head) has been set equal to zero.

The match resulted in the following correspondences. At a value for dimensionless pressure change, $(p_{2D})_M$, equal to 1.0, the corresponding value of measured pressure change, $(delp_2)_M$ was 69.7 kPa. This result was obtained by obtaining the slope, m, from a plot of average offset pressure versus log(time) and then applying

equation (K-13). The average offset pressure was calculated by arithmetically averaging the upper and lower zone pressures.

Using this correspondence between dimensionless and measured pressure change to fix the ordinate of the type curve match, the same-well pressure response was translated parallel to the abscissa until a suitable curve match resulted. This is the match shown in Figure M-1. Based on this positioning of the curves, a dimensionless time, $(Bt_{DV})_M$ equal to 1.0 was found to correspond to a time, t_M, of 12.0 days.

Using the equations and procedures described in Section K, sub-section 3.c), k_v/k_h was calculated. This type curve match result is compared with the input value in Figure M-1. As indicated, there is a 19.1% discrepancy, which represents a good correspondence between calculated and input values.

c) Pressure Averaging - Upper and Lower Zones Different

When the properties of the upper and lower zones differ, the resulting vertical pressure profile at the offset well will depend on whether injection occurs in the more transmissible or less transmissible zone.

Consider a reservoir with upper and lower zones of equal thickness but distinctive permeabilities. In the example to be presented, the permeability of one zone is twice that of the other. The vertical pressure profile at the offset well at a given time will depend on whether injection is into the more permeable or less permeable zone. This is illustrated in Figure M-2, where vertical pressure profiles after 30 days of injection are shown.

The plot indicates that when fluid is injected into the less permeable zone, the pressure response at the offset well is higher than would be the case if injection had been directed into the more permeable zone. An arithmetic average of each of these profiles would yield significantly different values of average pressure. However, since the pressure response at the offset well is supposed to be equivalent to that which would occur in a system with strictly horizontal flow, there should be only a single average offset pressure response for a given reservoir, irrespective of which zone the fluid is injected into.

A phenomenological explanation of this difference in vertical pressure profiles is advanced below, assuming that injection is directed to the more permeable zone:

i) For purposes of discussion, assume that injection into the less permeable zone represents the base case. Accordingly, the zone not receiving injection (i.e., the passive zone) in the base case is the more permeable one. The consequences of injection into the more permeable zone will be compared with those of the base case.

ii) For a fixed rate, injection into the more permeable zone requires half the pressure change needed to inject into the less permeable zone.

iii) Half the pressure change in the more permeable zone results in half the vertical rate (i.e., crossflow) across the low permeability layer compared with the rate which would occur if injection were into the less permeable zone (i.e., compared with the base case). This assumes that pressure in the passive zone is the same in both cases, as is suggested in Figure M-2.

iv) Half the rate into the passive zone, which has half the permeability of the passive zone in the base case, results in the same pressure in the passive zone as would occur in the base case. This conclusion is consistent with the assumption regarding passive zone pressure which was advanced in iii).

Based on the foregoing considerations, the following procedure was developed for calculating average offset well pressure from the vertical profiles generated in the model:

i) If injection is directed into the less permeable zone, the pressures in each model layer are averaged arithmetically. This reflects that choice of model configuration and parameters, since all layers were of equal thickness and possessed equal porosity. In a field situation, one set of offset well perforations in the upper zone, and one in the lower zone, a porosity-thickness weighting of each of the two pressures would be used.

ii) If injection is directed into the more permeable zone, then the pressure in each model layer is weighted according to the permeability of that layer. In terms of the field situation, the pressure in the upper zone is weighted in accordance with upper zone transmissibility (kh), and correspondingly for the lower zone. Average pressure is calculated by summing the transmissiblity-weighted pressures and dividing by the total transmissibility.

Figures M-3 and M-4 illustrate single-phase flow type curve matches in which the two offset well pressure averaging techniques are used. Figure M-3 represents water injection into the lower permeability zone, which occupies approximately 70% of the total thickness. Referring to the foregoing guidelines, vertical pressure profiles at the offset well were averaged arithmetically. Following the procedure for the modified EE&A analysis, a k_v/k_h value was calculated which differs from the input value by only 2.3%. Figure M-4 reflects water injection into the high permeability zone in a reservoir where the two zones are of equal thickness. In this instance, transmissibility weighting (referred to on the plot as permeability weighting) was used to obtain average offset pressures. The calculated and input values of k_v/k_h differ by 1.2%.

The results presented in Figures M-3 and M-4 tend to confirm the overall validity of the modified EE&A approach, as it applies to single-phase flow, including the offset well pressure averaging procedure.

d) Additional Cases - Upper and Lower Zones Different

An additional difference between the cases illustrated in Figures M-3 and M-4 pertains to hydrostatic gradient (head). In the case of Figure M-3 it was present, whereas it was absent in Figure M-4. Figure M-5 illustrates the results of a type curve fit of data from a case which resembles that of Figure M-4, in that head is absent, except that the injection interval is now in the lower permeability zone. The discrepancy between calculated and input values of k_v/k_h is 20.5%, which is good.

Thus far, cases have been presented in which the low permeability layer is either at mid-formation or 30% above the base of the formation. Figure M-6 illustrates a case in which the low permeability layer is now 70% above formation base, and injection is into the higher permeability zone. Hydrostatic gradient has been included. The resulting discrepancy between calculated and input values of k_v/k_h is 13.0%, which is very good.

2. GAS INJECTION

a) General

In all of the cases involving gas injection, the bottomhole rate varies so that normalization procedures have been used. In

most of these instances, the varying bottomhole rate is due to the combination of a constant surface rate and varying bottomhole injection pressure. However, one case, which is identified in subsequent discussion, incorporates a constant bottomhole pressure with a varying surface rate.

b) Advantage of Forcing the Ordinate

In Section K, the procedure for type curve matching included a step which utilized available data to determine the ordinate of the type curve fit, leaving only the abscissa to be matched. All of the foregoing type curve fits for water injection employed this ordinate forcing approach in generating a match.

The difference in results between an unforced and a forced fit is illustrated in Figures M-7 and M-8 for the case of gas injection. Gas is injected into the lower permeability zone, and the low permeability layer is located 30% up from the base of the formation.

Figure M-7 shows the unforced fit. The correspondence between the same-well pressure data and the type curve is excellent, suggesting that a good fit has been obtained. However, subsequent calculation of k_v/k_h results in a 30.4% discrepancy. While this is within the limits of acceptability, it is rather high. Figure M-8 illustrates the fit when the ordinates are forced. The resulting discrepancy of 19.2% represents a significant improvement.

Figures M-8P and M-8S illustrate respectively the pressure and gas saturation profiles in the active region after 30 days of injection in the case presented in Figure M-8. The injection interval is positioned 0.5 M below the top of the formation. Figure M-8P shows the high pressure gradient through the low permeability layer, analogous to the middle gradient presented in Figure M-2. Figure M-8S exhibits a fairly radial fluid invasion, as would be expected above the low permeability layer where the system behaves in a largely isotropic manner. The lowest gas saturation level depicted in the plot still has not reached the offset well (11.5 M from the injector) after 30 days of injection. Accordingly, distortion of the offset observation well pressures is likely minimal.

c) Sensitivities

Figure M-9 illustrates the type curve fit for a case which resembles that of Figure M-8, except that head effects are now included. The discrepancy between calculated and input values of k_v/k_h is 5.7%, which represents a significantly closer correspondence than that presented in Figure M-8. This suggests that the inclusion of head, and the corresponding need to adjust pressures to a common datum, does not introduce additional error into the well test analysis procedure.

Figures M-9P and M-9S present the respective pressure and gas saturation contour plots after 30 days of gas injection. Comparison of the pressure contours in Figure M-9P, which includes head, and Figure M-8P, which does not, illustrates the differences due to water gradient. When Figures M-9S and M-8S are compared, the effect of gradient on gas advance is apparent. When there is no density difference between the injected gas and the displaced water (Figure M-8S) fluid displacement is fairly spherical. However, when the density difference is introduced (Figure M-9S), the gas tends to override the water and advance more rapidly towards the offset observation well, which is located 11.5 M from the injector.

Figure M-10 illustrates the type curve match, and associated results for a reservoir configuration in which the low permeability is located at mid-formation. Head effects have been included. The resulting discrepancy between calculated and input k_v/k_h is 7.6%, which represents a very good correspondence. Note that, since injection was into the higher transmissibility zone, average offset pressure was determined by transmissibility weighting. Figures M-10P and M-10S illustrate the corresponding pressure and gas saturation contours after 30 days of gas injection. As with the previous series, the effects of density difference are evident.

Figure M-11 presents the type curve match for a different set of zone permeabilities. In the other cases discussed in this section, the permeabilities in the two zones differ by a factor of two. In this instance, the upper zone permeability is 50% higher than the lower zone value. Otherwise, conditions are comparable to previously discussed cases. Head has been included, and the low permeability layer is situated at mid-formation. The resulting correspondence between calculated and input k_v/k_h is excellent. Associated pressure and gas saturation contours after 30 days of gas injection are shown in Figures M-11P and M-11S respectively.

Figure M-12 is based on the identical permeability distribution to that of Figure M-10. However, whereas the porosity value in all other cases is 0.03, a value of 0.06 was input in this

case. The result is an excellent correspondence between calculated and input values of k_v/k_h. Pressure and gas saturation contours after 30 days of gas injection are illustrated in Figures M-12P and M-12S respectively. A comparison of Figure M-12S with Figure M-10S demonstrates the effect of the higher porosity in retarding the advance of the gas.

Figure M-13 illustrates the results of a case which examines the effect of wellbore damage on the calculation of k_v/k_h. Although the offset observation well will be located beyond any wellbore damage which may occur in a virgin oil sand, that same wellbore damage will directly affect the injection pressure. And since the injection pressure is used in the normalization procedure to determine instantaneous bottomhole rate, it is important to determine whether distortions due to wellbore damage will introduce significant inaccuracies. The basic reservoir configuration is identical to that presented in Figure M-9, except that a zone of reduced permeability, extending 2.0 M outward, has been imposed around the injection interval. The resulting discrepancy between calculated and input values of k_v/k_h is 4.8%, which indicates an excellent correspondence. Inasmuch as severe damage is not common in oil sand (and not likely, given the resistance to fluid invasion) this result suggests that the modified EE&A analysis technique, including normalization, will not be significantly compromised by the presence of damage. Associated pressure and gas saturation contours after 30 days of gas injection are shown in Figures M-13P and M-13S respectively.

In all of the foregoing cases, surface gas injection rate has been constant, and bottomhole rate has changed with changing bottomhole pressure. The case illustrated in Figure M-14 involves a constant bottomhole pressure boundary condition, so that bottomhole rate variation is induced by a constant terminal pressure boundary condition. The resulting discrepancy between calculated and input values of k_v/k_h is 6.6%, which indicates a very good correspondence. Associated pressure and gas saturation contours after 30 days of gas injection are shown in Figures M-14P and M-14S respectively.

N. CRITERIA FOR SELECTION OF RESERVOIR

The theoretical basis of well test analysis techniques includes a number of assumptions regarding the characteristics of the subject reservoir. In practice, it is not feasible to comply with many of the restrictions implied by these assumptions. However, this does not necessarily represent a fatal drawback. For example, in the case of certain types of reservoir heterogeneity, reliable values of reservoir parameters can be determined, even though homogeneity is generally the prevailing assumption. Similarly, as demonstrated in this study, the assumption of single-phase flow can be circumvented in certain circumstances, and the basic analysis techniques can be adapted to two phase flow.

Following is an itemization of major assumptions which underlie the analysis techniques, and some discussion of the importance of each:

1) Homogeneity in Permeability and Porosity

In the case of Prats, homogeneity is assumed throughout the reservoir. As demonstrated in Section L, a more or less random distribution of permeabilities violates the assumption but does not invalidate the analysis technique. An analogous result could be expected for effective porosity.

In the case of EE&A, homogeneity is assumed within each of the major zones (i.e., the upper zone, lower zone and intervening low permeability layer). It is anticipated that a more or less random permeability distribution within any or all of these zones would not be prejudicial to the result. For example, referring to Figure M-2, it is apparent that, consistent with the assumptions of the technique, there is very little pressure drop vertically within the upper and lower zones. Imposition of some variation in permeability about the mean value would alter this very little. The EE&A technique measures the fluid resistance through the intervening low permeability layer. However, the effects of variation in the permeability of this layer should be little different from those described above for the Prats technique.

If there are significant large-scale changes in lithology within the region undergoing testing, these may cause distortions of a more serious nature. However, while it is impractical to guard against all complications, the modified testing techniques have a decided advantage in that they require two wells. This provides

some reservoir sampling within the active flow region so that there is a higher probability of recognizing gross lithology changes. The impact of such lithologic features would have to be assessed on an individual case basis, most likely with numerical modelling techniques.

2) Single-phase Flow

Much of this study concentrates on demonstrating that, under appropriate circumstances, the single-phase flow assumption can be violated with little loss in overall accuracy.

3) Constant Initial Pressure

Typically, well testing techniques assume a that a quiescent state prevails prior to implementation of the test. In practice, if there is an existing long-term pressure trend within the reservoir, this can be quantified through pressure monitoring prior to the test, and accounted for in the subsequent calculations.

In most instances involving a virgin oil sand, it is unlikely that there would be significant trends in reservoir pressure. Accordingly, this is is not expected to be a major consideration in the vast majority of situations.

4) Viscosity of the Displaced Fluid

An examination of the equations for calculating k_v/k_h, whether by the Prats or EE&A techniques, indicates that the result is independent of the viscosity of the displaced fluid.

5) Relative Permeability

As shown in Section G of this study, for a wide variety of gas-water relative permeability curves, the offset well pressure response is largely unaffected.

6) Extent of Reservoir

The analysis techniques assume that the reservoir is infinite acting. Given the relatively modest extent of the active zone (e.g., 30 M over a 30 day test), it is very likely that this assumption will remain valid throughout the duration of the test.

7) Overlying/Underlying High Mobility Zones

The analysis techniques assume that the reservoir is delimited above and below by no-flow boundaries. This can be a particularly important assumption. For example, if the oil sand is underlain by a water zone of significant thickness, this may distort the results significantly. If that water zone is part of an active aquifer of appreciable size, or if a large gas cap overlies the oil zone, the no-flow boundary condition is replaced with one which more closely approximates a constant-pressure boundary condition. This can cause serious distortion of the results, just as it will in conventional well test situations.

In summary, the reservoir need not be homogeneous, although sudden large scale changes in lithology horizontally may present problems. In determining k_v/k_h, it is not necessary to know either the relative permeability characteristics of the fluids or their viscosities. Variations in initial pressure are unlikely in a virgin oil sand but could be accounted for. Reservoirs should be selected in which there are no significant underlying or overlying thief zones (i.e., zones containing high mobility fluids).

O. REFERENCES

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2. Winestock, A.G. and Colpitts, G.P.
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3. Horner, D.R.
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4. Prats, M.
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5. Ehlig-Economides, C. and Ayoub, J.A.
"Vertical Interference Testing Across a Low Permeability Zone"
SPE Formation Evaluation (October 1986) 497-510

TABLES

TABLE G - 1

MODEL GRID BLOCK CONFIGURATION

I. MODEL RADIAL GRID BLOCK CONFIGURATION

RADIAL GRID BLOCK NO.	GRID BLOCK OUTER RADIUS, M	GRID BLOCK MID-POINT RADIUS, M
1	2	1
2	4	3
3	6	5
4	8	7
5	10	9
6	13	11.5
7	17	15
8	23	20
9	30	26.5
10	40	35
11	55	47.5
12	80	67.5
13	105	92.5
14	130	117.5
15	131	130.5
16	231	181
17	431	331
18	1431	931
19	11431	6431

II. MODEL VERTICAL GRID BLOCK CONFIGURATION

THERE ARE 15 LAYERS, EACH 1 METER IN THICKNESS.

TABLE G - 2

MODEL RESERVOIR PARAMETERS

INITIAL RESERVOIR PRESSURE, kPa	1000
EFFECTIVE POROSITY, FRACTION	0.03
EFFECTIVE PERMEABILITY, UM2	9.8690E-05
GAS VISCOSITY, mPa.S	0.012
GAS VOL. EXPANSION FROM 1000 kPa TO S.C.	10
GAS VOL. EXPANSION FROM 10000 kPa TO S.C.	100
WATER VISCOSITY, mPa.S	1.00
WATER COMPRESSIBILITY, kPa-1	1.45E-06
WATER DENSITY, KG/M3	1000
CAPILLARY PRESSURE, kPa	0

TABLE G - 3

GAS INJECTION AT A CONSTANT SURFACE RATE
NORMALIZATION OF PRESSURE

EXAMPLE PROCEDURE

SURFACE INJECTION RATE = 0.50 M3/DAY
INITIAL BH PRESSURE = 1000 KPA (pi)
BOTTOMHOLE INJ. RATE @ 1000 KPA = 0.05 M3/DAY (qc)

	@ INJECTOR			@ OBSERVATION PT.	
	OBS.	CALC.	CALC.	OBS.	CALC.
DAYS	INJECTOR BHP,KPA	BHP ADJ. FACTOR*	BH RATE q(t)** M3/DAY	MEASURED OFFSET PRESSURE @R=11.5M p(t) KPA	NORM. OFFSET PRESS.*** @R=11.5M pn(t) KPA
0.03	1071	1.071	0.0467	1000	1000.0
0.16	1115	1.115	0.0448	1005	1005.6
0.78	1153	1.153	0.0434	1027	1031.1
2.78	1173	1.173	0.0426	1055	1064.5
4.78	1178	1.178	0.0424	1071	1083.6
6.78	1181	1.181	0.0423	1081	1095.7
8.78	1183	1.183	0.0423	1088	1104.1
10.78	1184	1.184	0.0422	1094	1111.3
12.78	1185	1.185	0.0422	1099	1117.3
14.78	1186	1.186	0.0422	1103	1122.2
16.78	1187	1.187	0.0421	1106	1125.8
18.78	1187	1.187	0.0421	1109	1129.4
20.78	1187	1.187	0.0421	1112	1132.9
22.78	1187	1.187	0.0421	1114	1135.3
24.78	1188	1.188	0.0421	1117	1139.0
26.78	1188	1.188	0.0421	1119	1141.4
28.39	1188	1.188	0.0421	1120	1142.6
30.00	1189	1.189	0.0421	1122	1145.1

* IN THIS EXAMPLE, GAS VOLUME IS A LINEAR FUNCTION OF PRESSURE.
REFERENCE PRESSURE (AND ALSO ORIGINAL RESERVOIR PRESSURE) IS 1000 KPA.
THEREFORE, BH ADJUSTMENT FACTOR = INJECTOR BHP/1000.

** $q(t) = qi/(\text{BH ADJUSTMENT FACTOR})$

***$pn(t) = pi + (qc/q(t))(p(t) - pi)$

TABLE I - 1

PRATS ANALYSIS TECHNIQUE
CALCULATION OF Kv/Kh - SINGLE-PHASE FLOW

INPUT DATA

WELL/RSVR PARAMETERS:		BOUNDARY CONDITIONS:	
Kh, UM2	9.869E-05	q, M3/D	0.05 AT WELL
Ø, FRACTION	0.03	q, M3/D	0.00 OUTER BDRY
U, mPa.S	1		
h, M	15		
c, kPa-1	1.45E-06		
rw, M	0.0762		
re, M	11431		
Kv:			
ISOTROPIC	9.869E-05		
ANISOTROPIC	9.869E-06		

INTERMEDIATE EVALUATION

VALUE OF K/Øuc USED IN DETERMINING Kv/Kh:

K/Øuc BASED ON INPUT = 2268

K/Øuc CALCULATED FROM TEST 1772 (ISOTR.)
1787 (ANISOTR.)

ANALYSIS RESULTS

	Kv/Kh INPUT	PRATS WITH INPUT VALUE OF K/Øuc	PRATS WITH CALC. VALUE OF K/Øuc
ISOTROPIC	1.00	0.654	0.979
	% DEVIATION	-34.6%	-2.1%
ANISOTROPIC	0.10	0.0818	0.106
	% DEVIATION	-18.2%	6.0%

TABLE J - 1

MODIFIED PRATS ANALYSIS TECHNIQUE
CALCULATION OF Kv/Kh
TWO-PHASE FLOW (GAS INJECTION)
ANISOTROPIC RESERVOIR

INPUT DATA

WELL/RSVR PARAMETERS:		BOUNDARY CONDITIONS:	
Kh, UM2	9.869E-05	q, M3/D @ SC	0.50 AT WELL
Kv, UM2	9.869E-06	q, M3/D	0.00 OUTER BDRY
Ø,FRACTION	0.03		
Uw, mPa.S	1		
h, M	15	INJECTED GAS PROPERTIES:	
c, kPa-1	1.45E-06		
rw, M	0.0762	Ug, mPa.S	0.012
re, M	11431		

Gas Vol.Conversion Factor,Eg:
Eg = PRESSURE(kPa)/100
Vol.@ P = (Vol @ atm)/Eg

ANALYSIS RESULTS

SOURCE OF SLOPE, m	SOURCE OF DELP1	Kv/Kh
INPUT	INPUT	0.1000
SAME-WELL OBS. PT.	SAME-WELL OBS. PT.	0.0878
OFFSET OBS.WELL	SYNTHESIZED (I.E., SAME-WELL DATA POINT PLUS OFFSET SLOPE).	0.0997

TABLE J - 2

MODIFIED PRATS ANALYSIS TECHNIQUE
CALCULATION OF Kv/Kh
TWO-PHASE FLOW (GAS INJECTION)
ISOTROPIC RESERVOIR

INPUT DATA

WELL/RSVR PARAMETERS:		BOUNDARY CONDITIONS:	
Kh, UM2	9.869E-05	q, M3/D @ SC	0.50 AT WELL
Kv, UM2	9.869E-05	q, M3/D	0.00 OUTER BDRY
Ø,FRACTION	0.03		
Uw, mPa.S	1		
h, M	15	INJECTED GAS PROPERTIES:	
c, kPa-1	1.45E-06		
rw, M	0.0762	Ug, mPa.S	0.012
re, M	11431		

Gas Vol.Conversion Factor,Eg:
Eg = PRESSURE(kPa)/100
Vol.@ P = (Vol @ atm)/Eg

ANALYSIS RESULTS

SOURCE OF SLOPE, m	SOURCE OF DELP1	Kv/Kh
INPUT	INPUT	1.000
SAME-WELL OBS. PT.	SAME-WELL OBS. PT.	0.854
OFFSET OBS.WELL	SYNTHESIZED (I.E., SAME-WELL DATA POINT PLUS OFFSET SLOPE).	0.895

TABLE G - 4

HORIZONTAL FLOW

CALCULATION OF HORIZONTAL PERMEABILITY
TWO-PHASE FLOW (GAS INJECTION)

INFLUENCE OF DISTANCE TO OFFSET WELL

DISTANCE TO OFFSET OBS.WELL M	K/(Øuc)		Kh, ØM2	
	INPUT	CALCULATED	INPUT	CALCULATED
7.0	2268	728	9.869E-05	7.560E-05
11.5	2268	1453	9.869E-05	8.843E-05
20.0	2268	1898	9.869E-05	9.425E-05
26.5	2268	2254	9.869E-05	9.869E-05

NOTES:

Pressures normalized.

Offset well data used to calculate k/Øuc.
Offset well data used to determine slope, m.

TABLE L - 1

MODIFIED PRATS ANALYSIS TECHNIQUE
CALCULATION OF Kv/Kh
TWO-PHASE FLOW (GAS INJECTION)

INFLUENCE OF DISTANCE TO OFFSET WELL
ISOTROPIC & ANISOTROPIC RESERVOIRS

DISTANCE TO OFFSET OBS.WELL M	Kv, µM2		Kh, µM2		Kv/Kh	
	INPUT	CALCULATED	INPUT	CALCULATED	INPUT	CALCULATED
	ISOTROPIC PERMEABILITY:					
7.0	9.869E-05	9.376E-05	9.869E-05	9.464E-05	1.00	0.991
11.5	9.869E-05	8.497E-05	9.869E-05	9.267E-05	1.00	0.917
20.0	9.869E-05	9.001E-05	9.869E-05	9.603E-05	1.00	0.937
	ANISOTROPIC PERMEABILITY:					
7.0	9.869E-06	6.958E-06	9.869E-05	1.263E-04	0.10	0.0551
11.5	9.869E-06	9.691E-06	9.869E-05	9.139E-05	0.10	0.106
20.0	9.869E-06	9.593E-06	9.869E-05	9.316E-05	0.10	0.103

NOTES:

Injection 11.5 M from base of reservoir.
Same-well observation 2.5 M from base of reservoir.

Pressures normalized.

Offset well data used to calculate k/Øuc.
Offset well data used to determine slope, m.

Same-well data used to select intercept (delp1).

TABLE L - 2

GAS INJECTION

INFLUENCE OF RANDOM PERMEABILITY DISTRIBUTION
IN ACTIVE FLOW REGION
ON CALCULATION OF VERTICAL PERMEABILITY
USING MODIFIED PRATS ANALYSIS TECHNIQUE

MODEL INPUT PERMEABILITIES:

RADIAL GRID BLOCK RANGE		VERTICAL GRID BLOCK RANGE		PERMEABILITY ΜM2
I1	I2	K1	K2	
1	2	1	3	2.382E-05
3	4	1	3	1.708E-04
5	6	1	3	2.885E-04
7	19	1	3	9.869E-05
1	2	4	6	1.814E-04
3	4	4	6	4.917E-05
5	6	4	6	7.380E-05
7	19	4	6	9.869E-05
1	2	7	9	2.100E-04
3	4	7	9	2.797E-05
5	6	7	9	1.392E-04
7	19	7	9	9.869E-05
1	2	10	12	5.770E-05
3	4	10	12	2.692E-04
5	6	10	12	1.637E-04
7	19	10	12	9.869E-05
1	2	13	15	1.649E-04
3	4	13	15	2.581E-04
5	6	13	15	1.604E-04
7	19	13	15	9.869E-05

COMPARISON OF MODEL DATA AND CALCULATED RESULTS:

	MODEL INPUT	CALCULATED
K/Øuc	2268	2227
Kh, ΜM2	9.124E-05	9.808E-05
Kv/Kh	0.8848	0.8013

TABLE L - 3

GAS INJECTION

INFLUENCE OF HIGHER PERMEABILITY LAYER
ON CALCULATION OF VERTICAL PERMEABILITY
USING MODIFIED PRATS ANALYSIS TECHNIQUE

MODEL INPUT PERMEABILITIES:

LAYERS	PERMEABILITY* ΜM2
1 THROUGH 7	0.0000986
8	0.0004935
9 THROUGH 15	0.0000986

*LOCAL ISOTROPY. WITHIN EACH GRID BLOCK Kh = Kv.

INJECTION & OBSERVATION POSITIONS (M ABOVE BASE):

MID-POINT OF INJECTION INTERVAL	11.5 (LAYER 12)
MID-POINT OF OBSERVATION INTERVAL	2.5 (LAYER 3)

INJECTOR-OFFSET HORIZONTAL DISTANCE 11.5 M

COMPARISON OF MODEL DATA AND CALCULATED RESULTS:

	MODEL INPUT	CALCULATED
Kh, ΜM2	1.253E-04	1.204E-04
Kv/Kh	0.776	0.854

FIGURES

SINGLE PHASE FLOW - PRESSURE TRANSIENT
INVESTIGATION RADIUS VS TIME

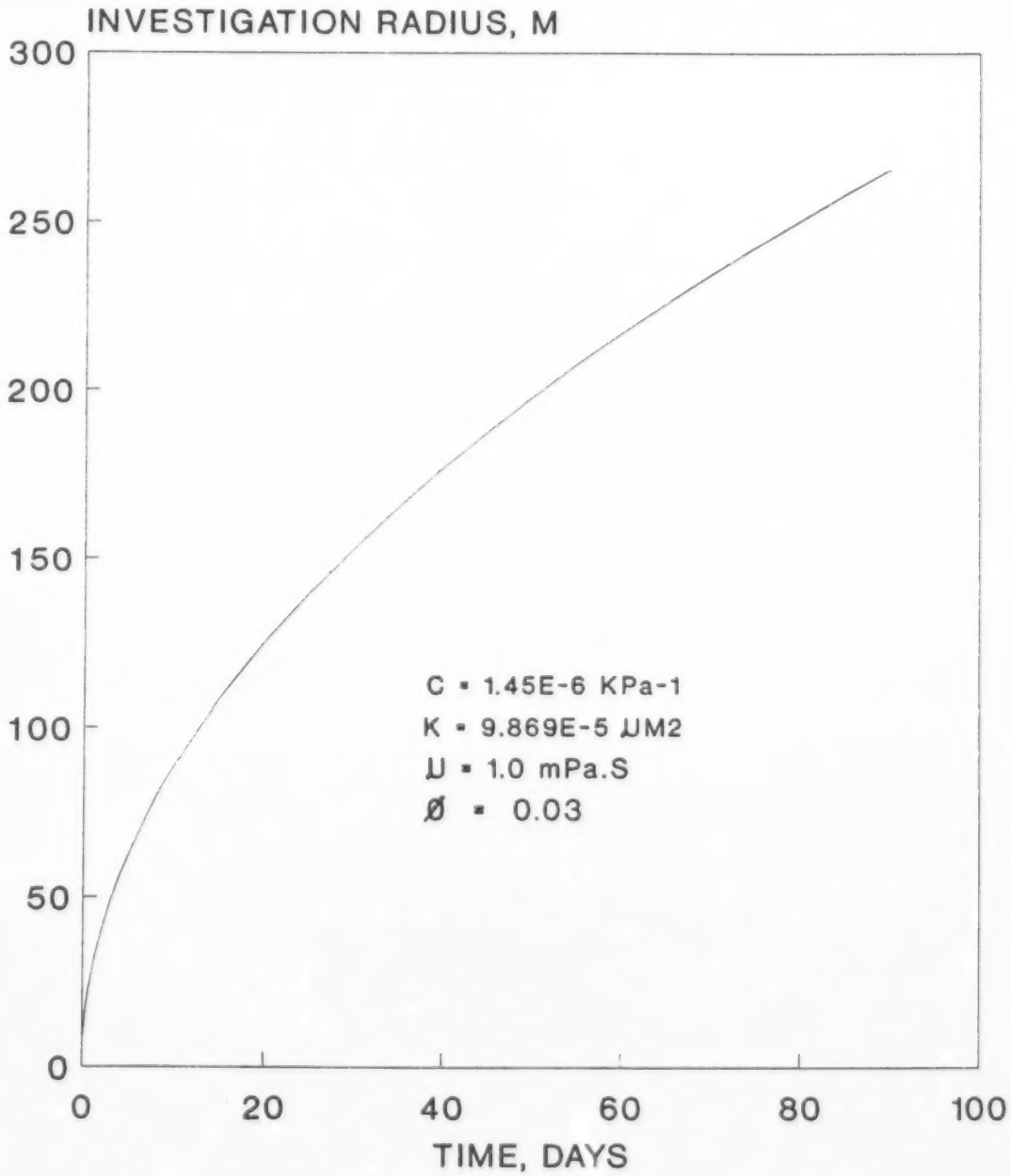


FIGURE F - 1

SINGLE-PHASE FLOW INJECTION
FLUID & INVESTIGATION RADII VS TIME

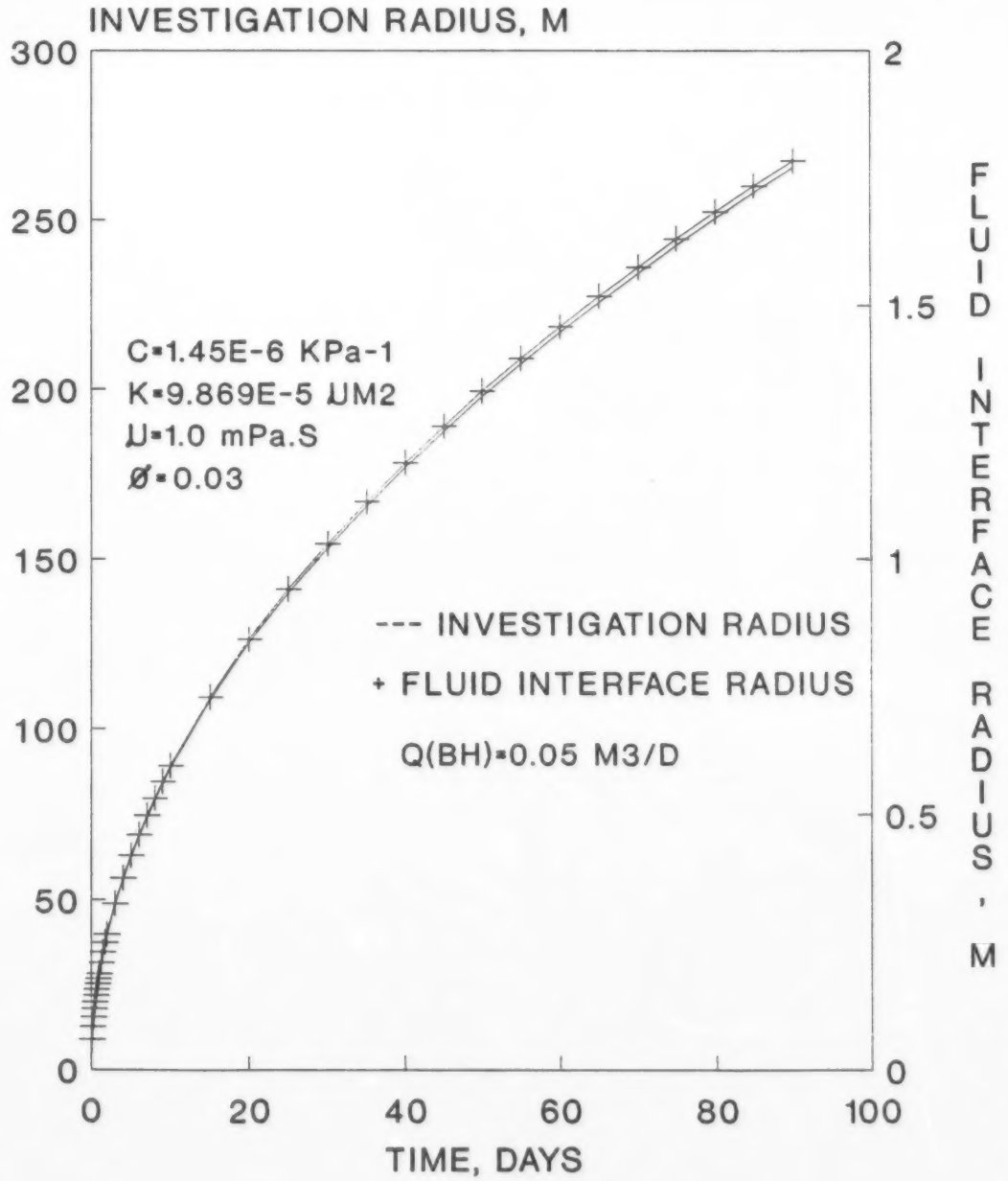


FIGURE F - 2

SINGLE-PHASE WATER INJECTION
MODEL & ANALYTICAL BH PRESS. RESPONSE

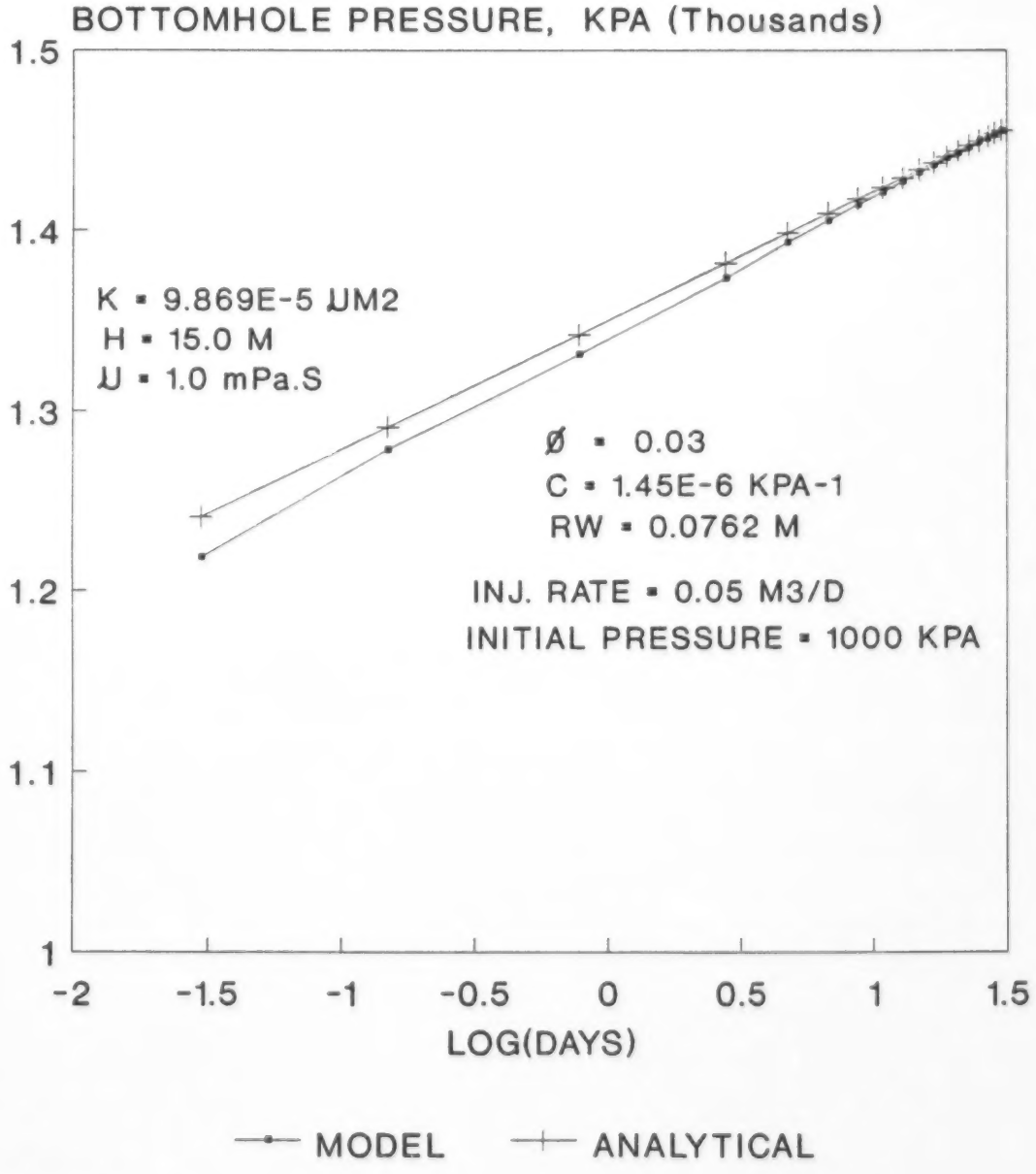


FIGURE G - 1

COMPARISON OF SINGLE & 2-PHASE FLOW PRESSURE RESPONSE AT INJECTOR

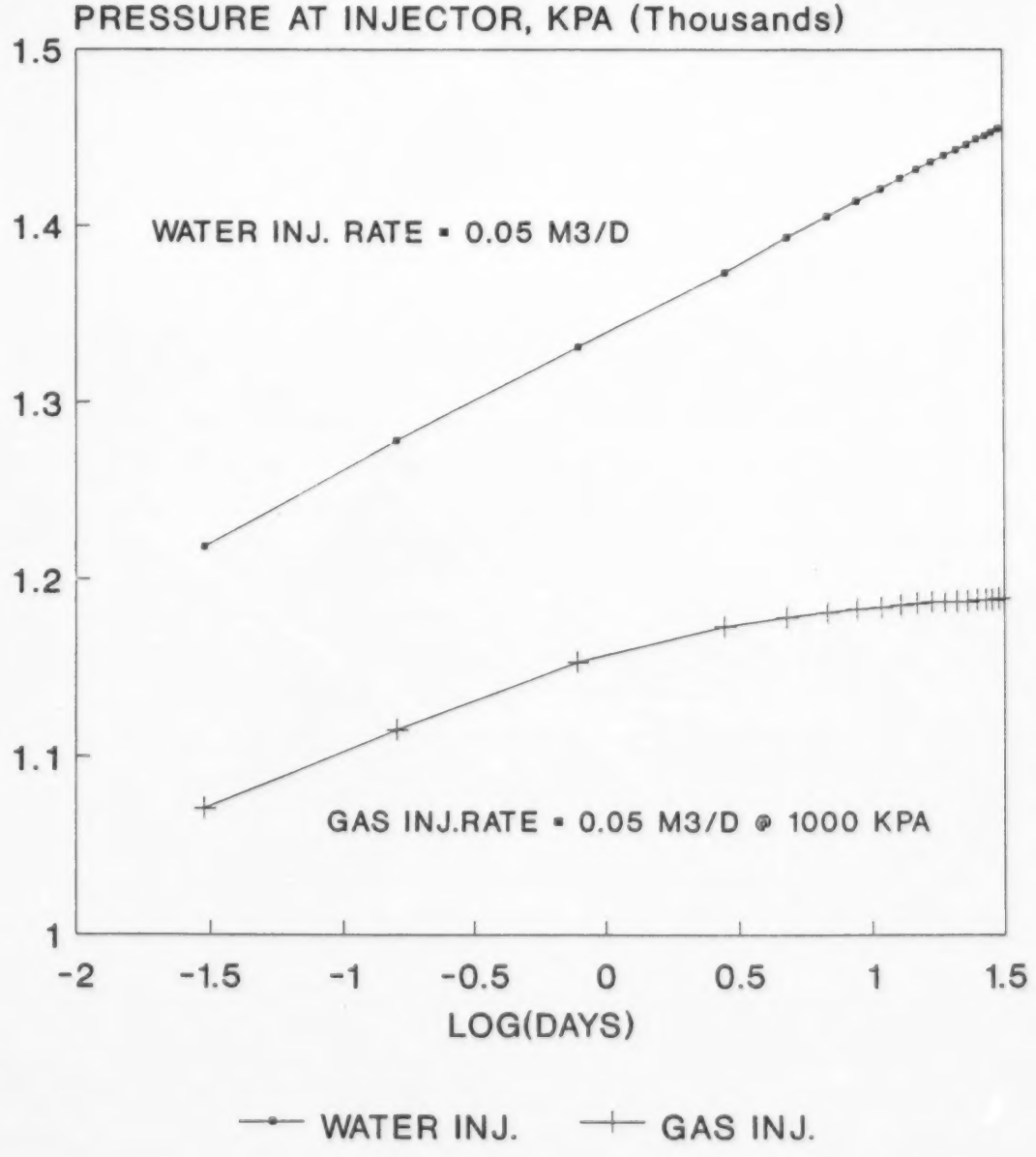


FIGURE G - 2

UPC

COMPARISON OF SINGLE & TWO-PHASE FLOW PRESS. RESPONSE @ 11.5 M FROM INJECTOR

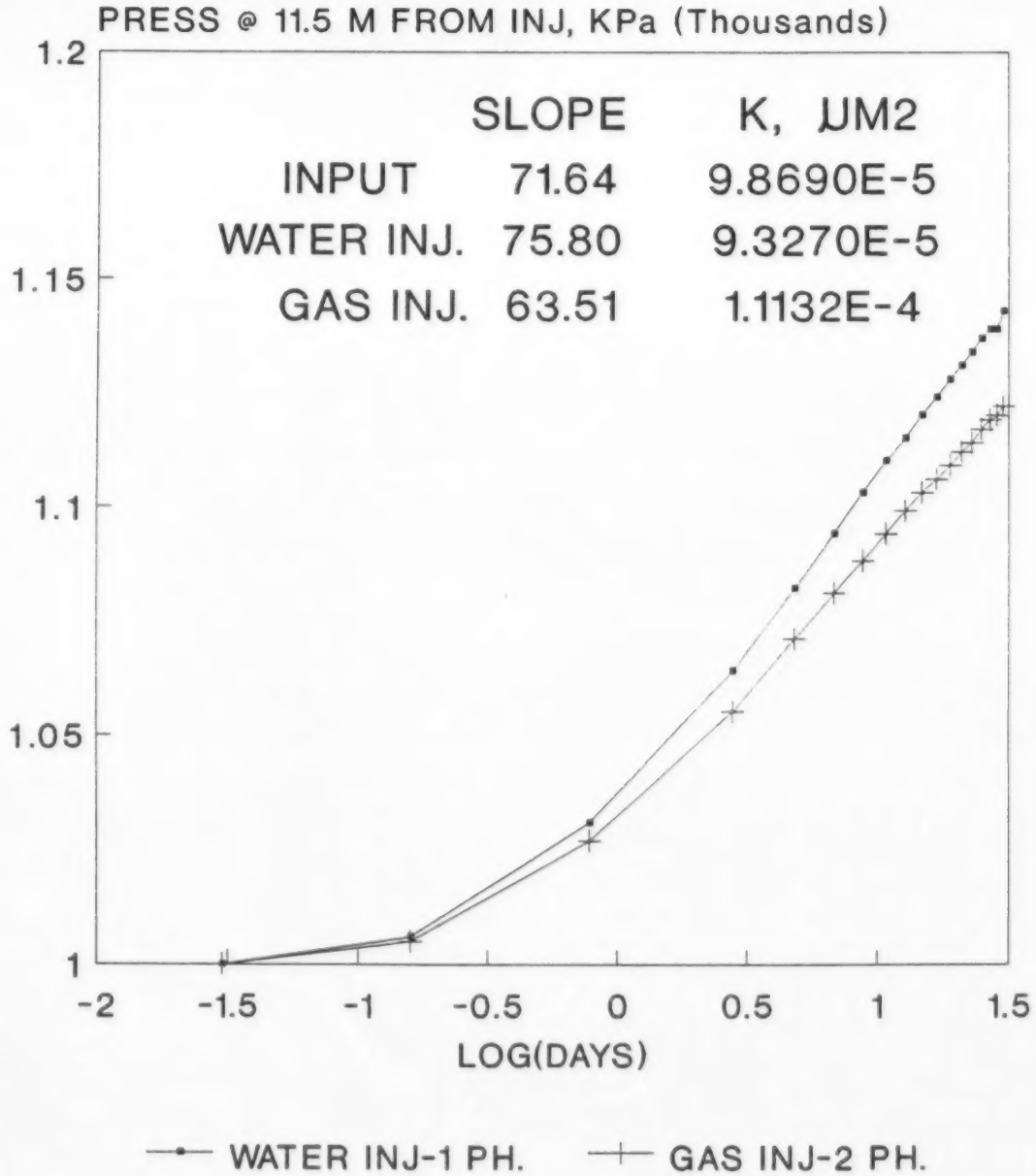


FIGURE G - 3

NORMALIZATION OF 2-PH. GAS INJECTION
PRESS. RESPONSE @ 11.5 M FROM INJECTOR

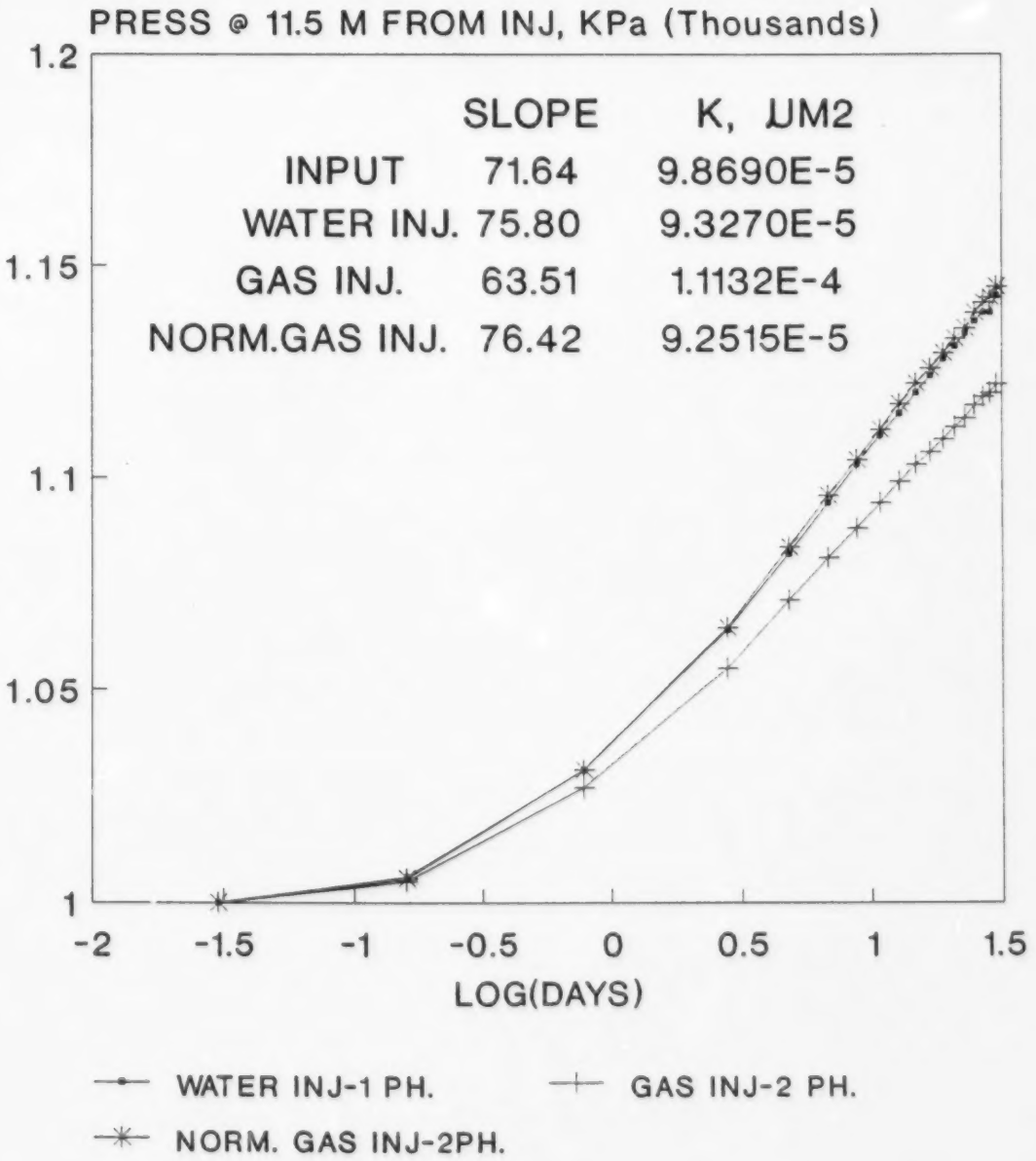


FIGURE G - 4

GAS INJECTION - HORIZONTAL FLOW
COMPARISON OF OFFSET PRESSURE RESPONSES

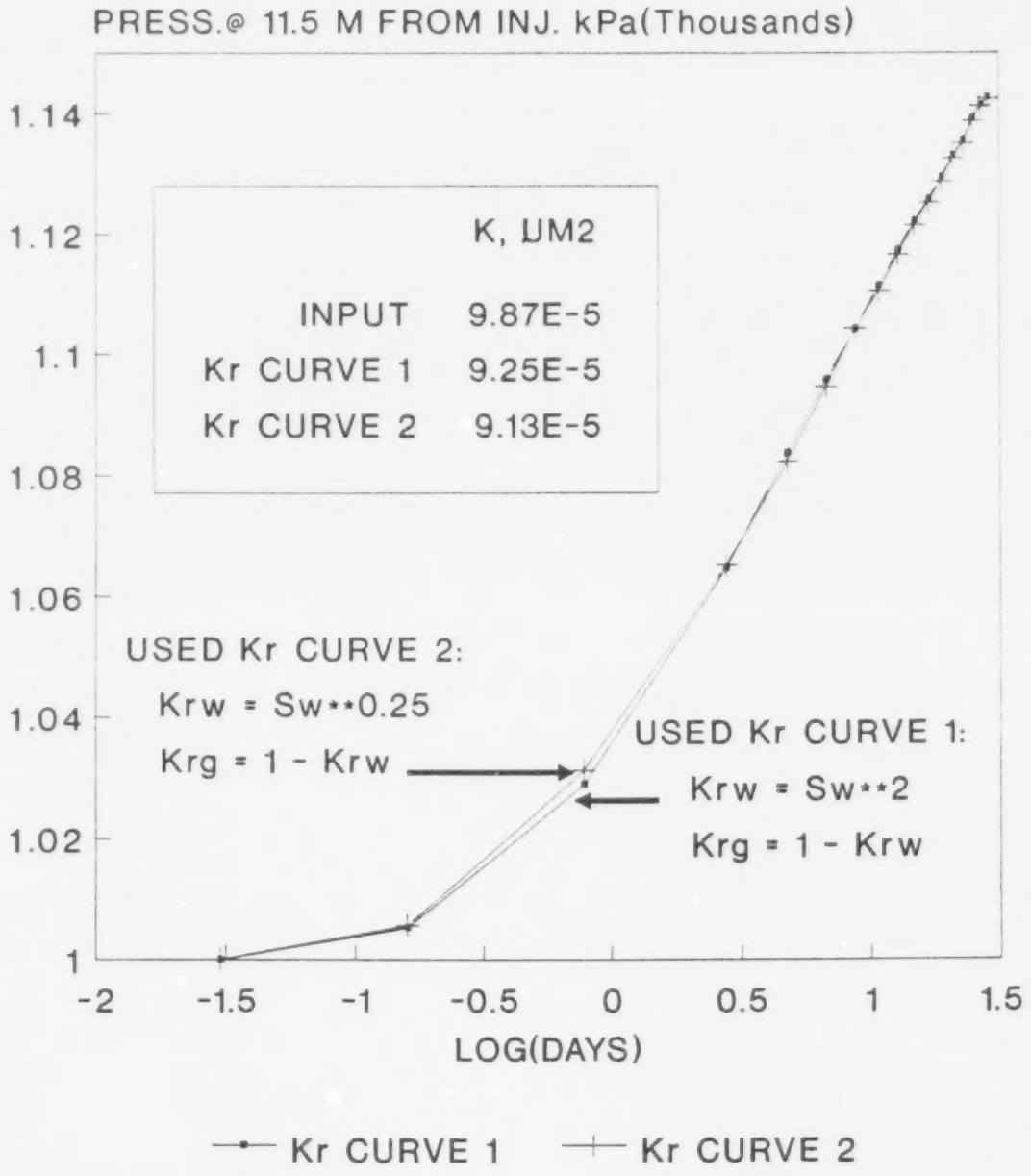


FIGURE G - 5

GAS INJECTION - HORIZONTAL FLOW
INFLUENCE OF RELATIVE PERMEABILITY

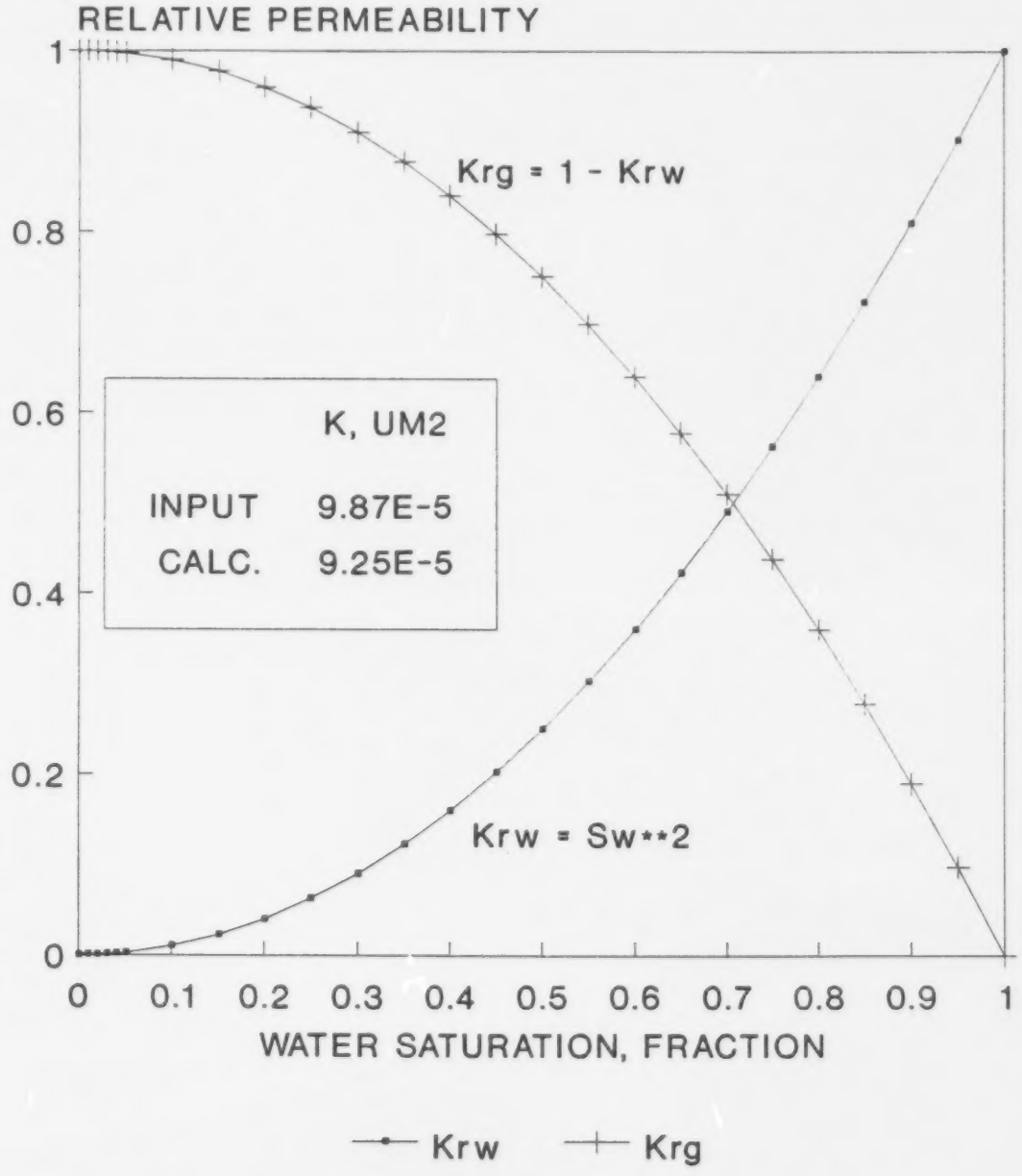


FIGURE G - 6

GAS INJECTION - HORIZONTAL FLOW
INFLUENCE OF RELATIVE PERMEABILITY

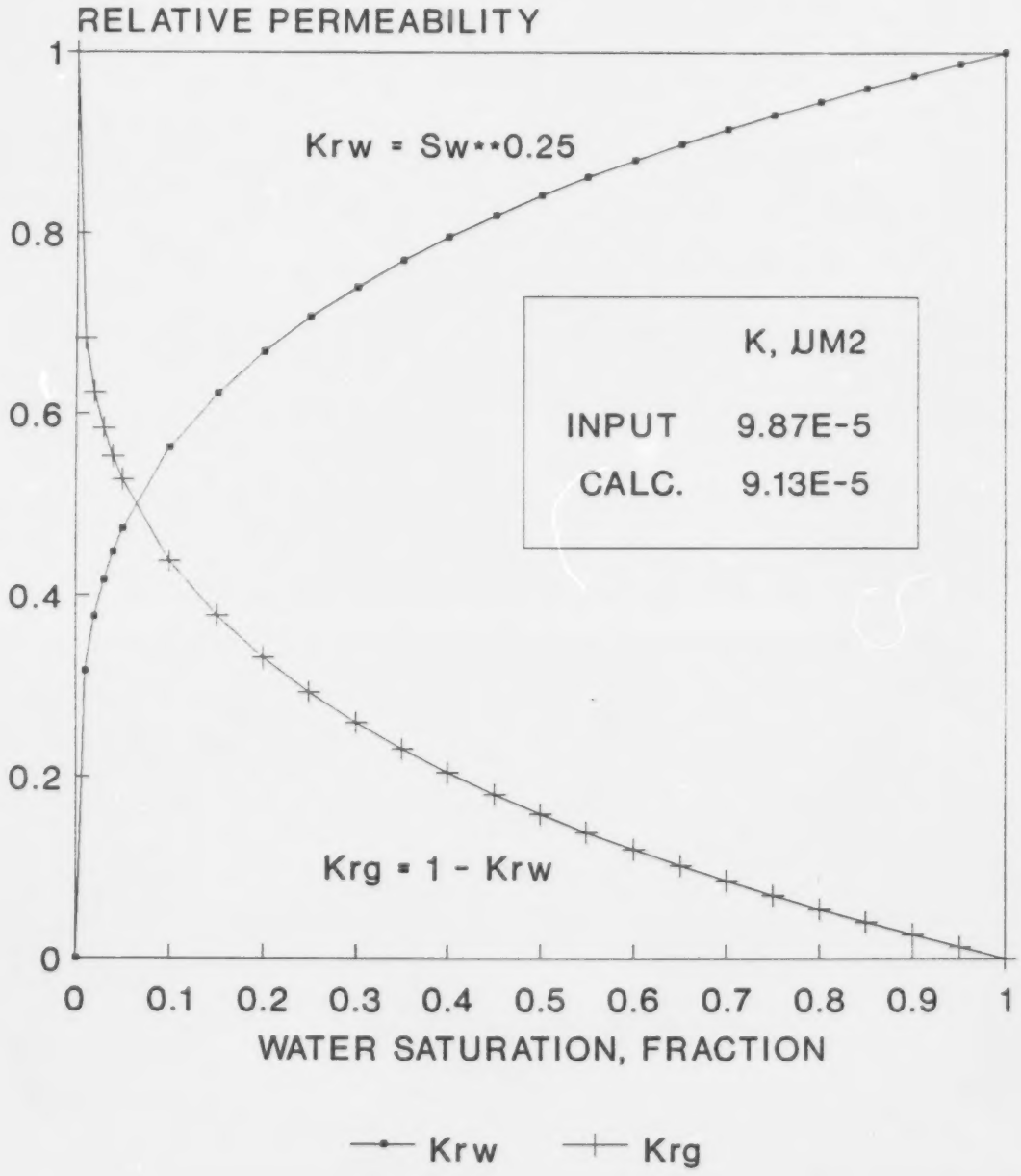


FIGURE G - 7

GAS INJECTION - HORIZONTAL FLOW
INFLUENCE OF RELATIVE PERMEABILITY

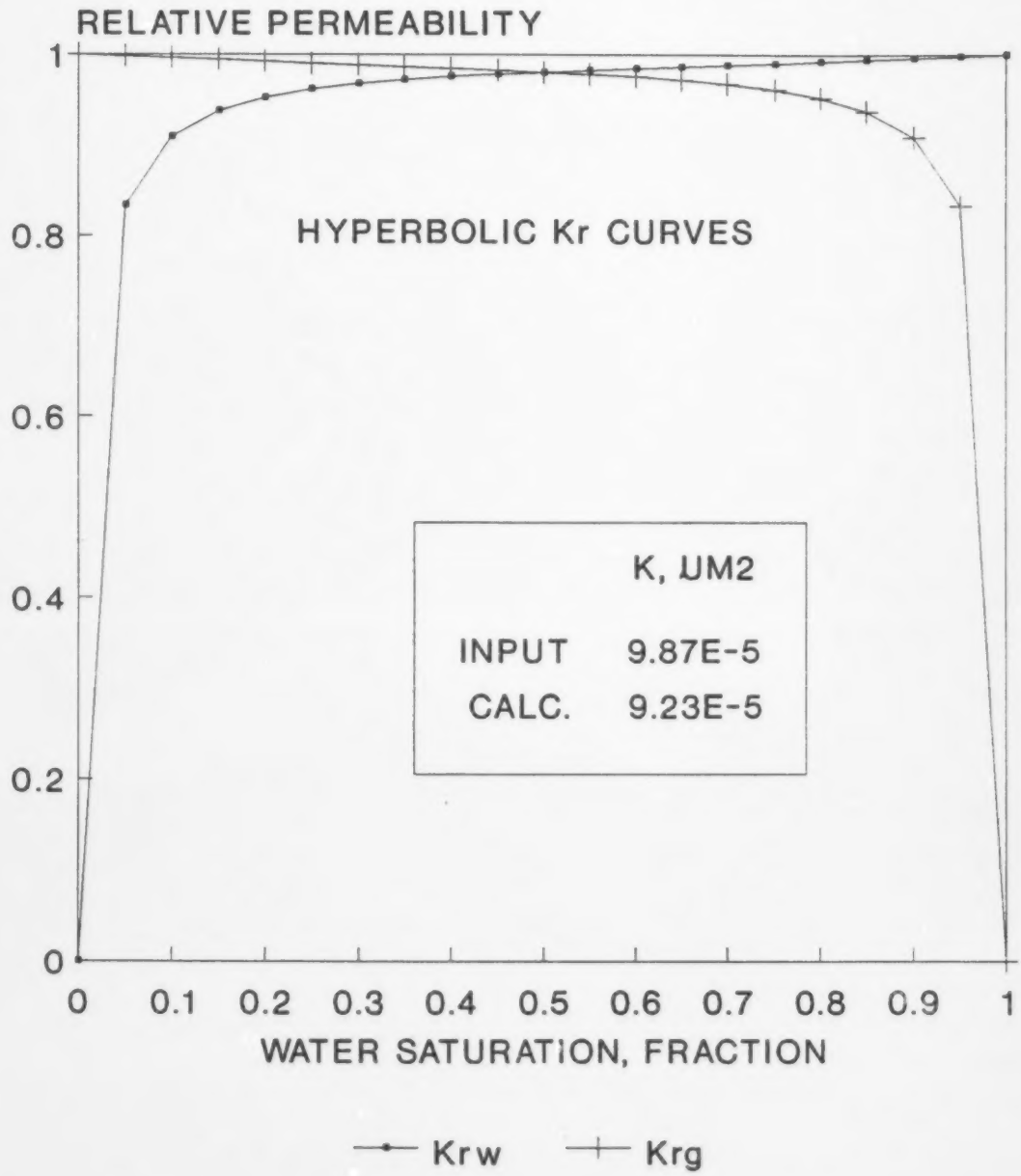


FIGURE G - 8

GAS INJECTION - HORIZONTAL FLOW
INFLUENCE OF RELATIVE PERMEABILITY

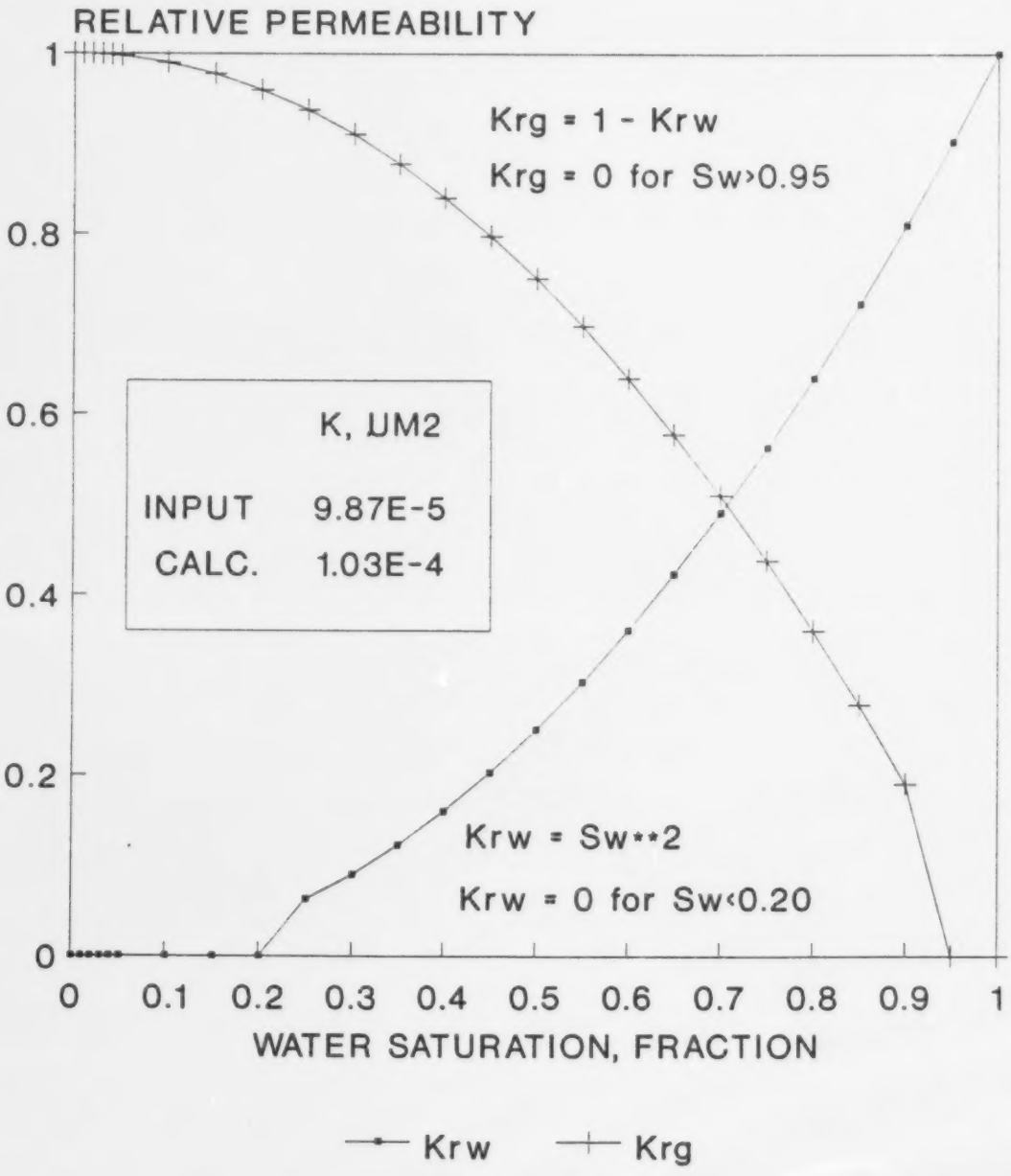


FIGURE G - 9

GAS INJECTION - HORIZONTAL FLOW
HORNER PLOT OF PRESSURE FALL-OFF

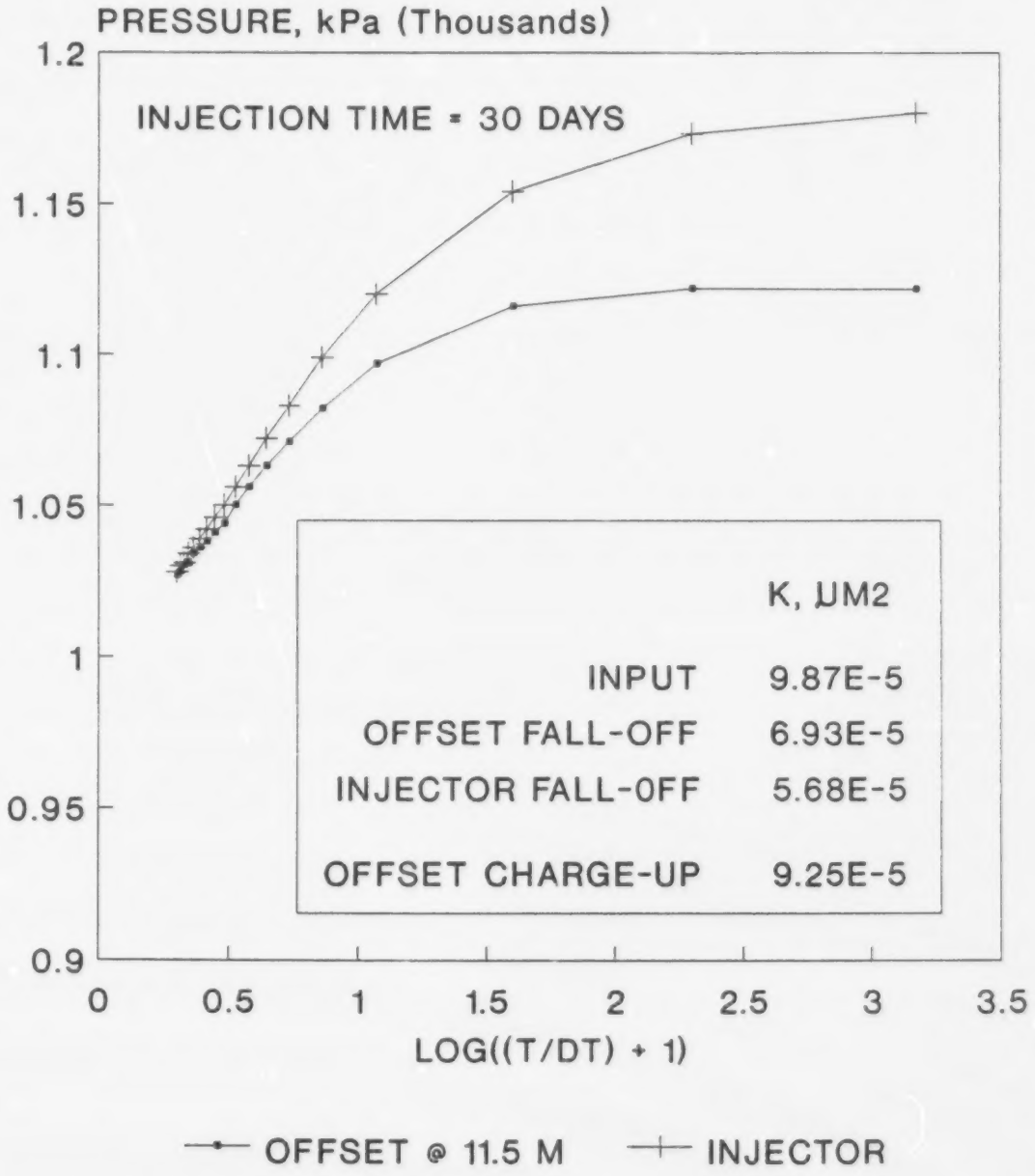


FIGURE G - 10

PRATS

WELL TEST ANALYSIS CONFIGURATION

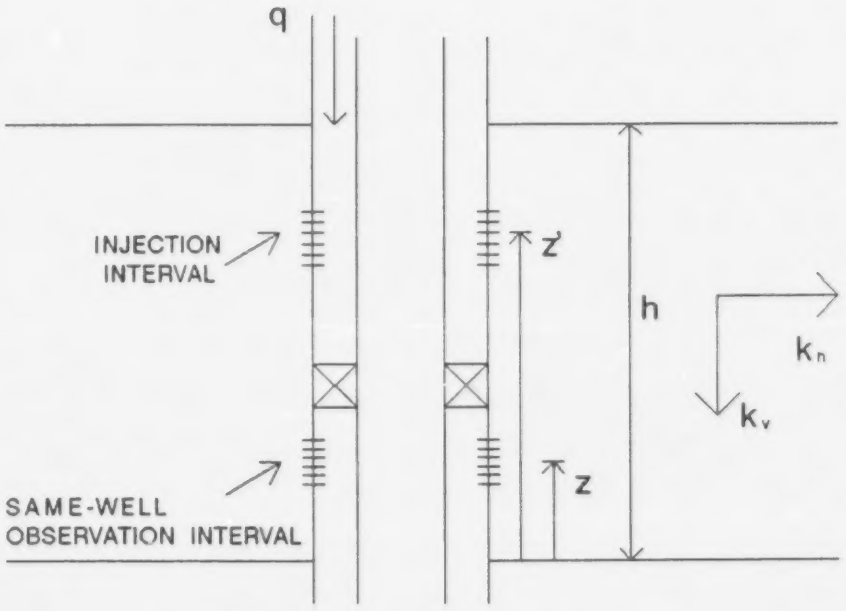


FIGURE H - 1

SINGLE-PHASE WATER INJECTION
PRATS ANALYSIS TECHNIQUE

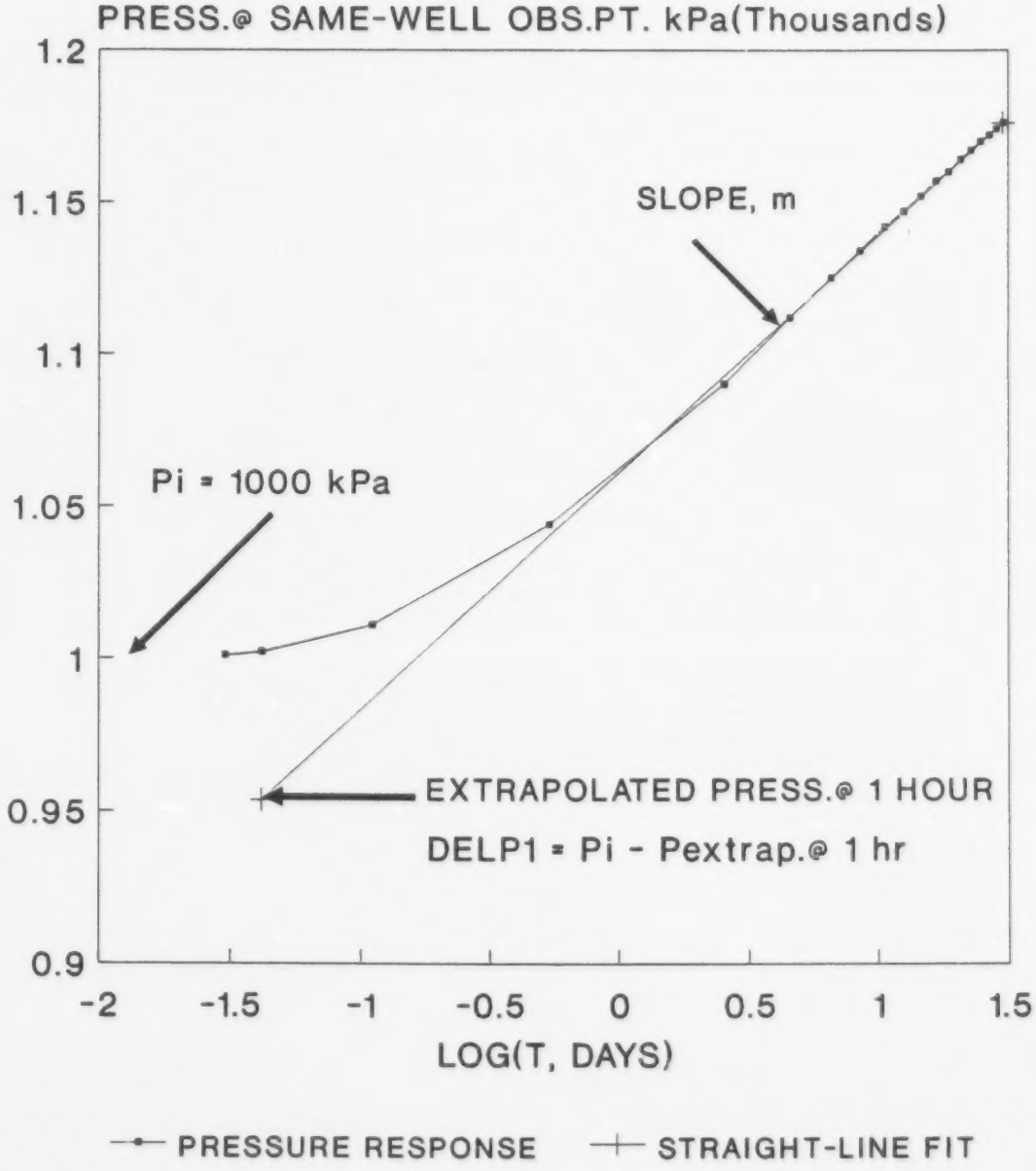


FIGURE H - 2

EHLIG-ECONOMIDES & AYOUB

WELL TEST ANALYSIS CONFIGURATION

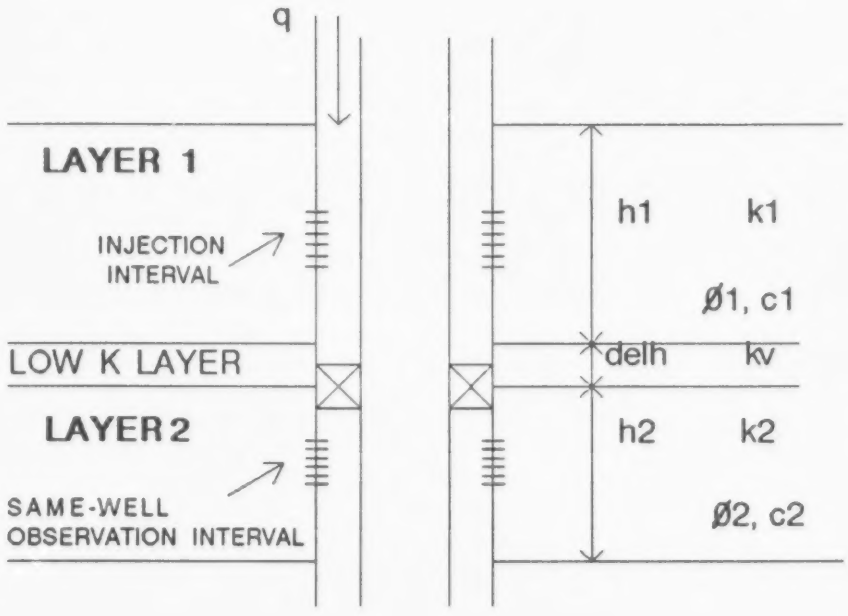


FIGURE H - 3

EHLIG-ECONOMIDES & AYOUB TYPE CURVE
LOG(p2D) VS LOG(BtDV)

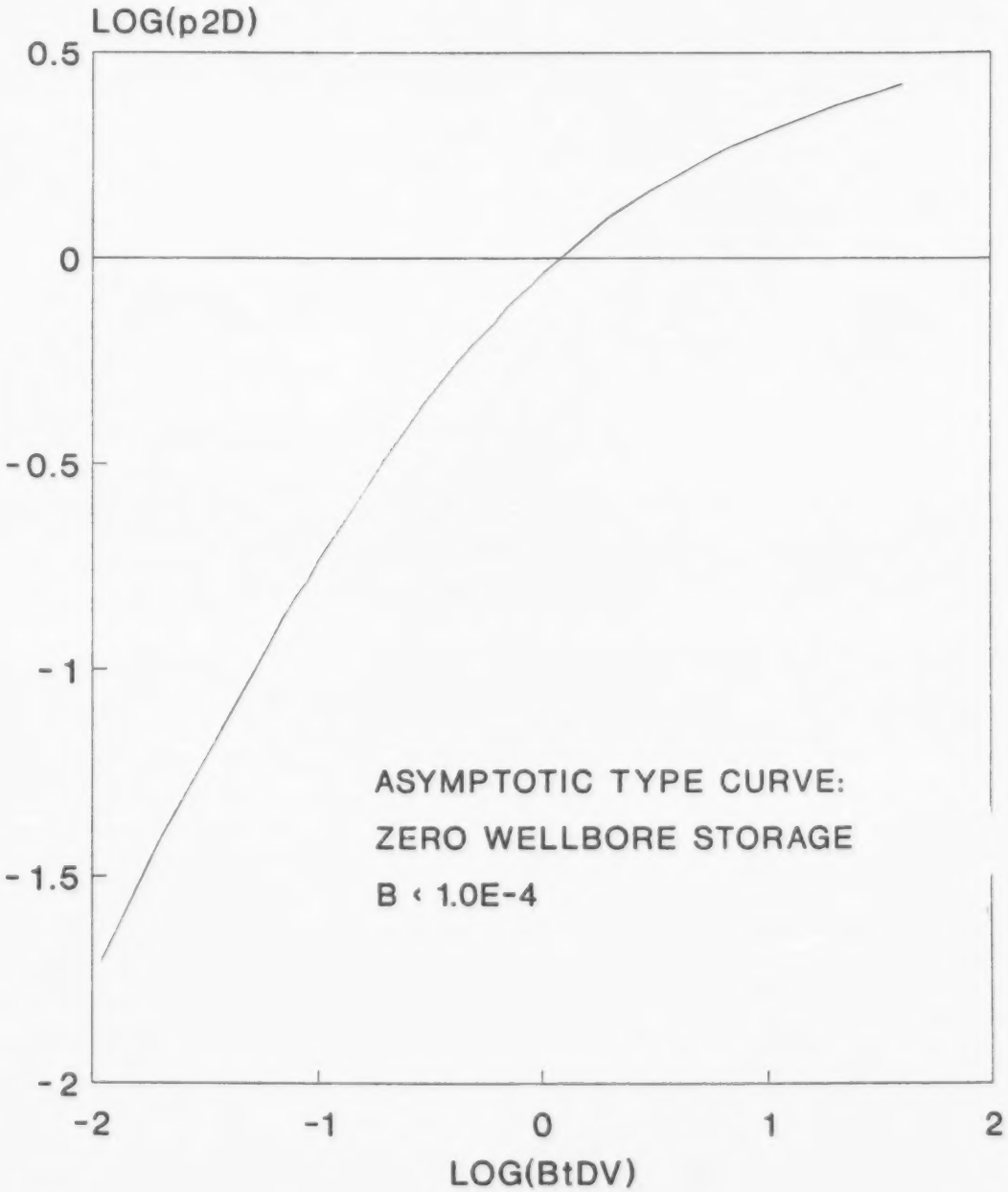
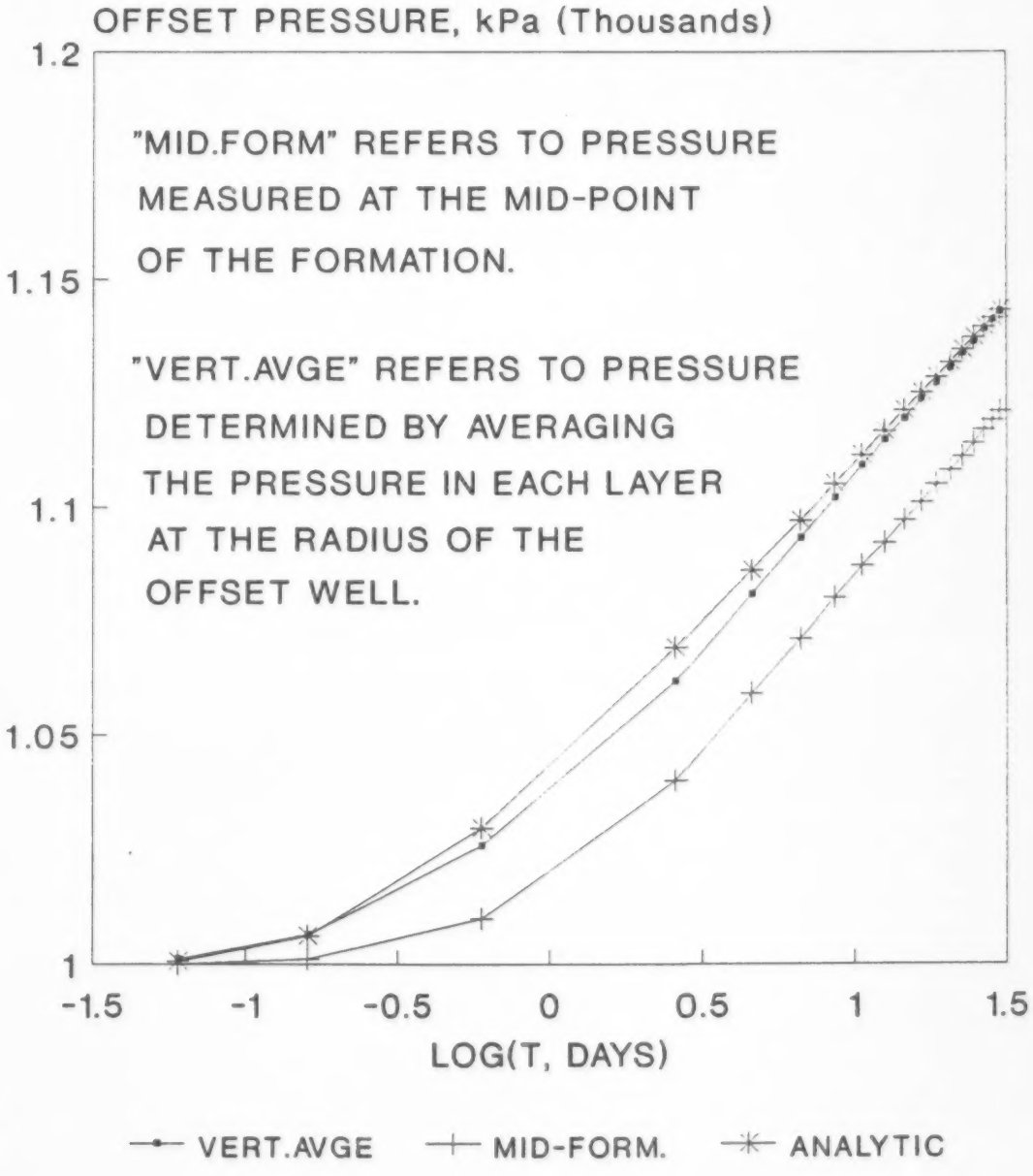


FIGURE H - 4

COMPARISON OF PRESSURES RESPONSES
WATER INJ. WITH VERTICAL FLOW COMPONENT



OFFSET WELL LOCATED 11.5 M FROM INJECTOR

FIGURE I - 1

GAS INJECTION - ANISOTROPIC RESERVOIR
MODIFIED PRATS ANALYSIS TECHNIQUE

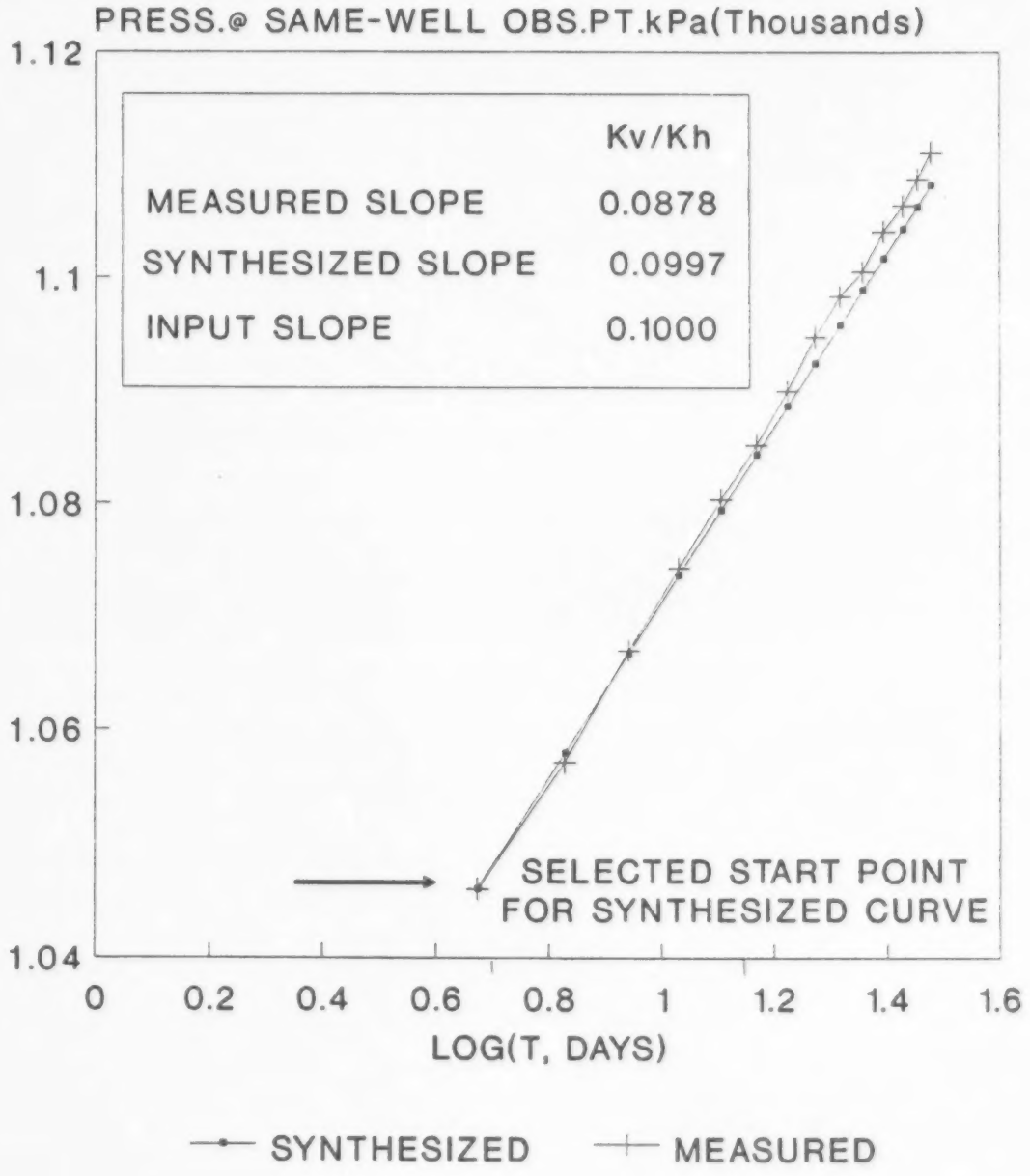


FIGURE J - 1

GAS INJECTION - ISOTROPIC RESERVOIR
MODIFIED PRATS ANALYSIS TECHNIQUE

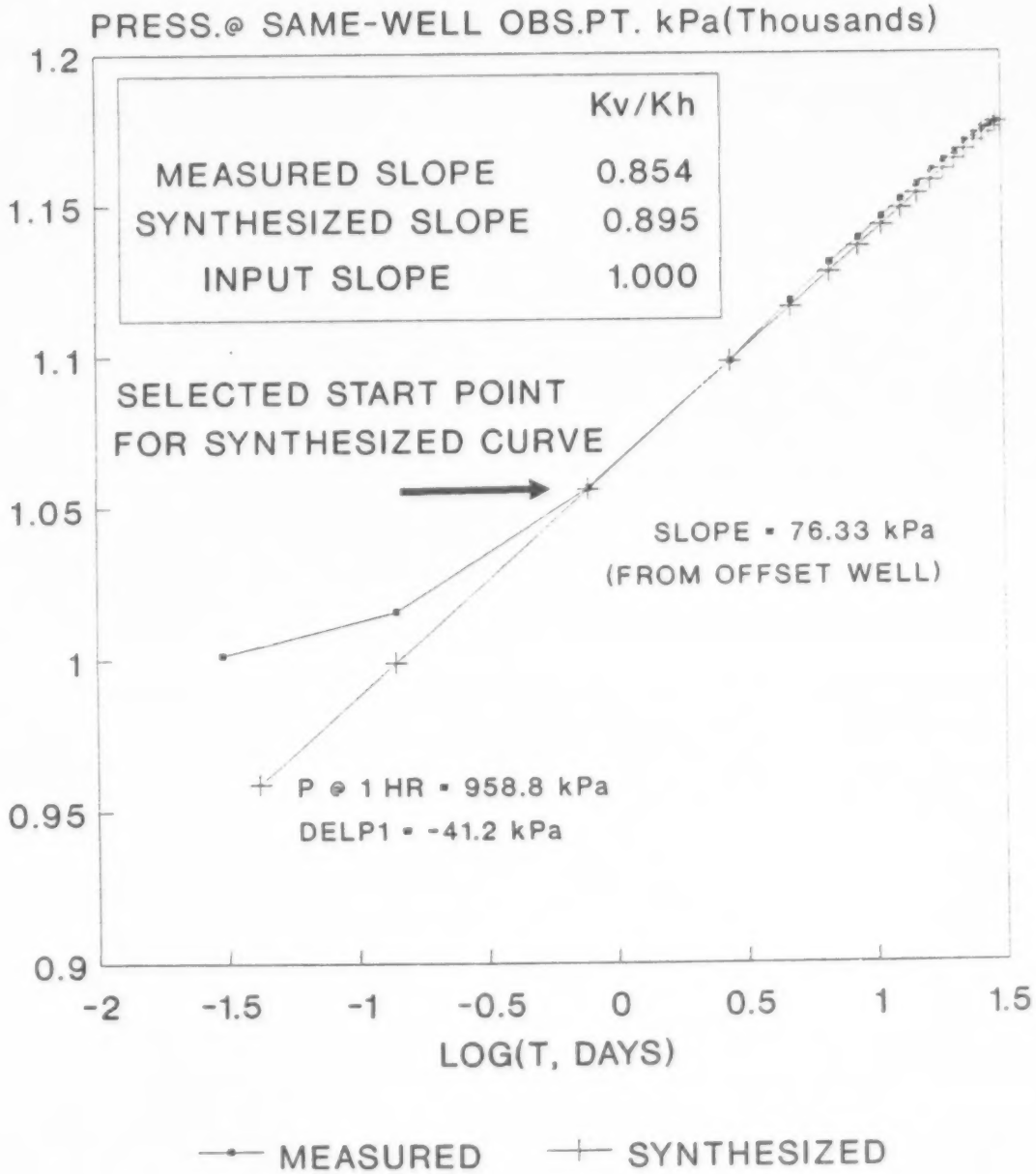


FIGURE J - 2

INFLUENCE OF ISOTROPY/ANISOTROPY & HEAD/NO HEAD ON SAME W.PRESS.RESPONSE

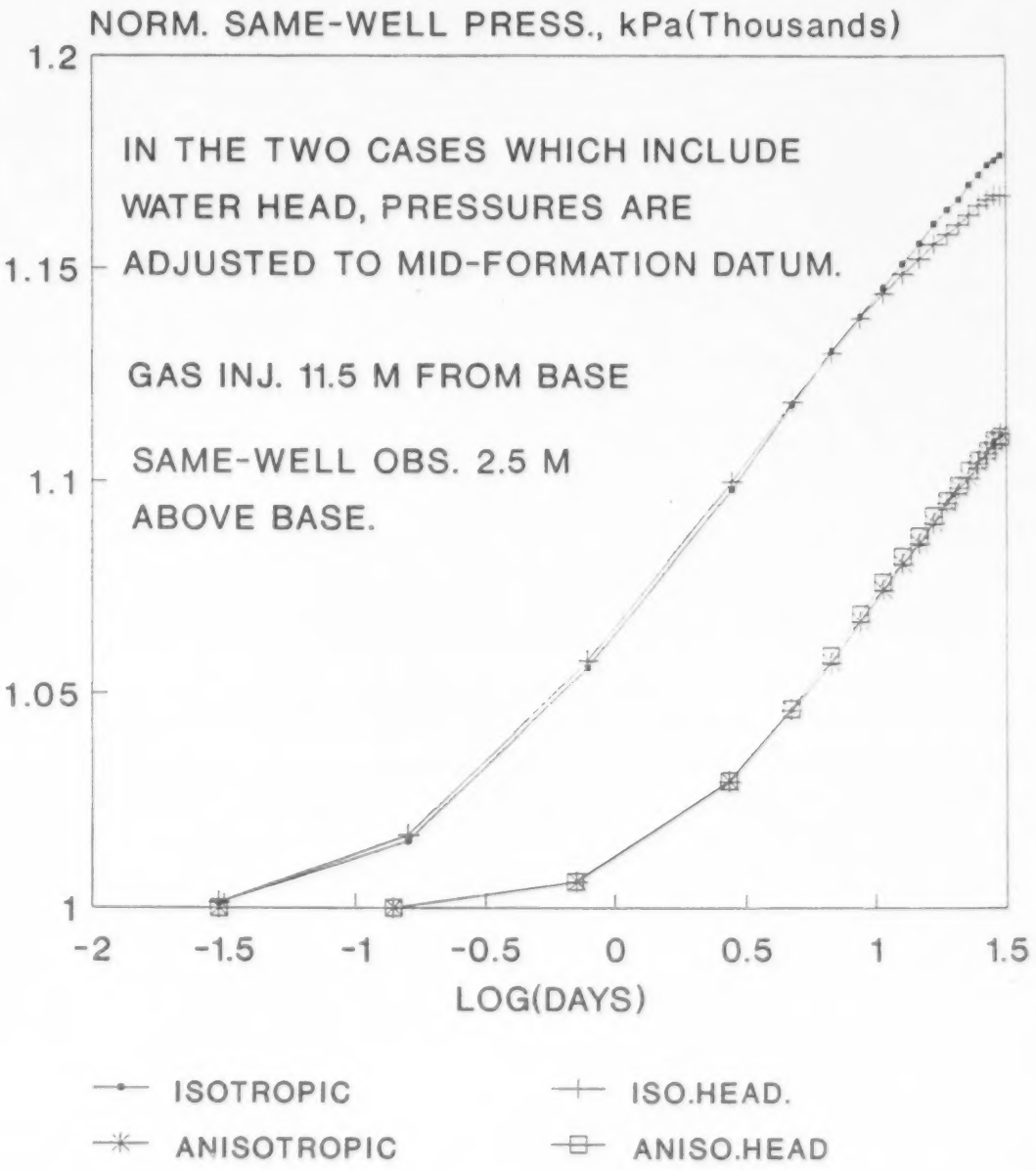


FIGURE J - 3

INFLUENCE OF ISOTROPY/ANISOTROPY & HEAD/NO HEAD ON AVGE.OFFSET PRESS.RESP

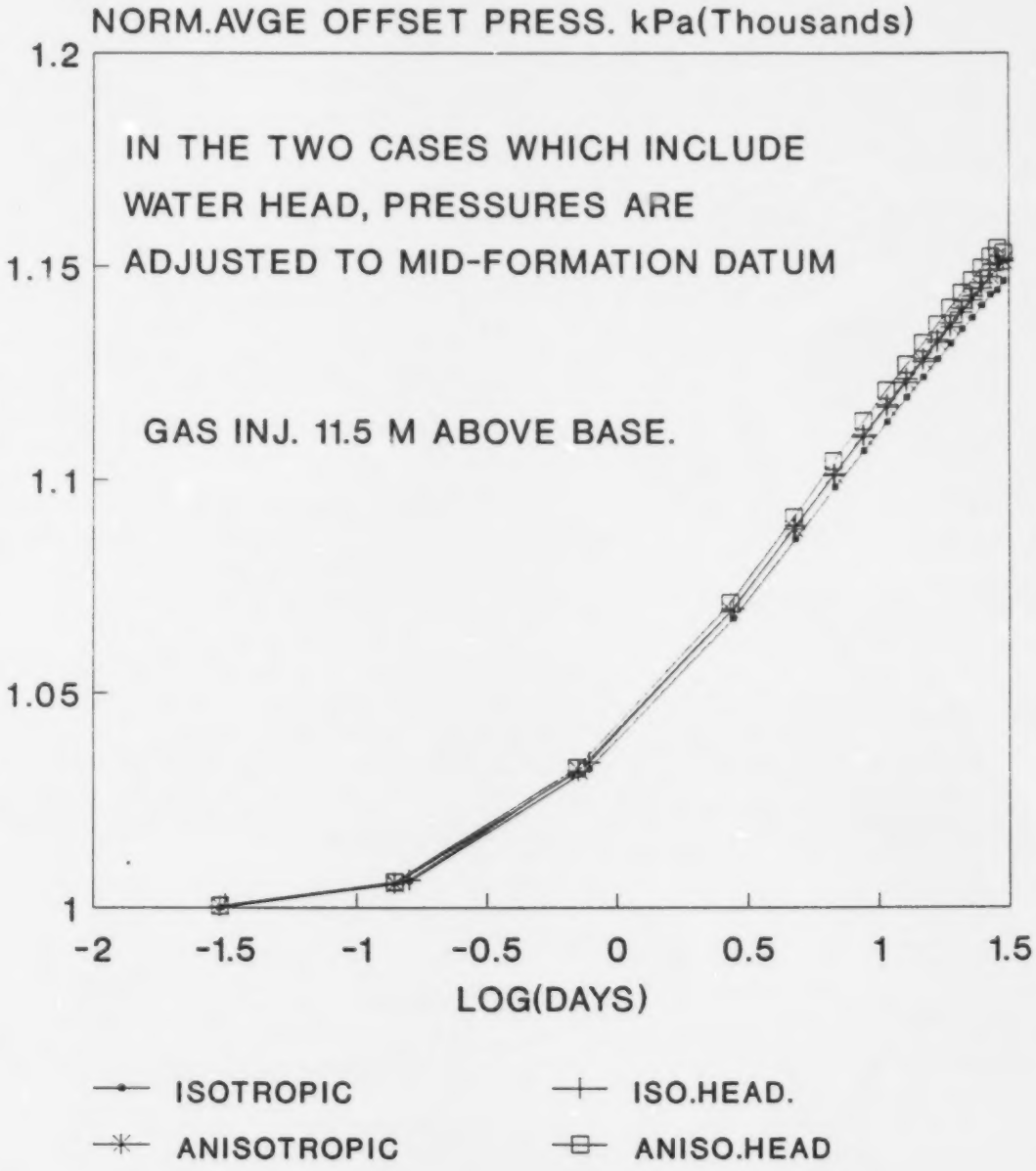


FIGURE J - 4

MODIFIED WELL TEST CONFIGURATION

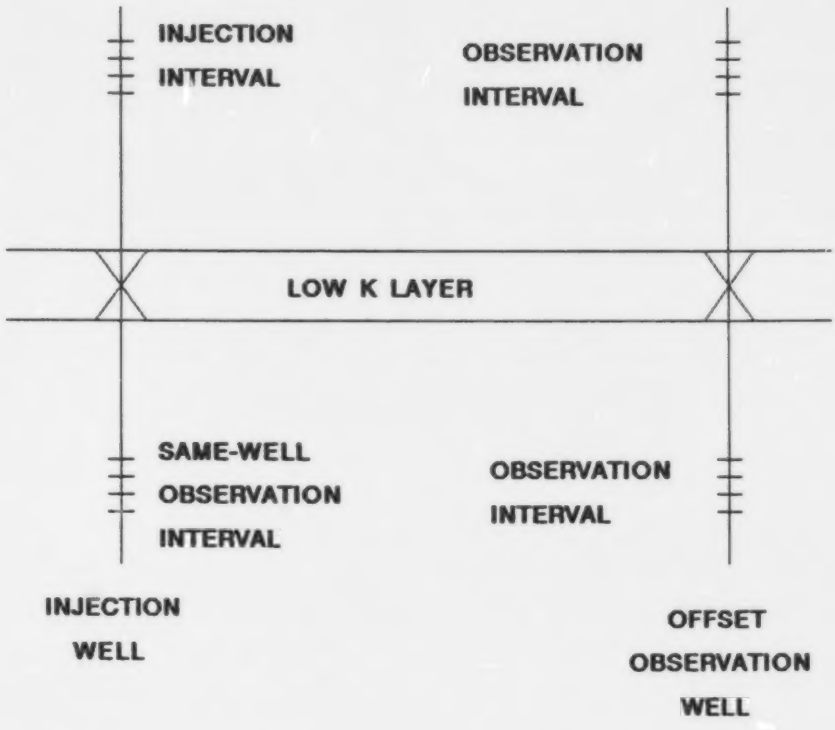
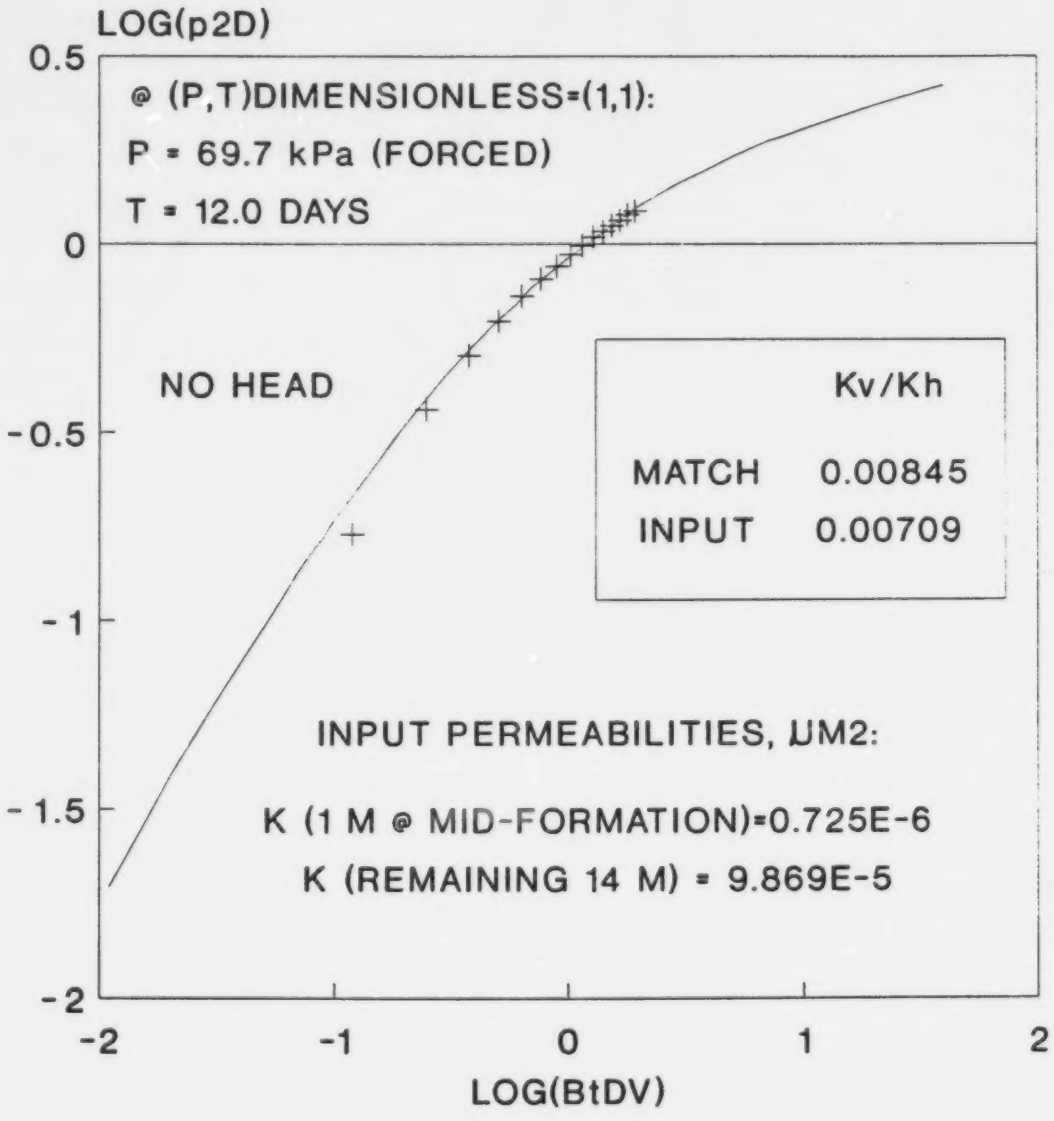


FIGURE K - 1

EE & A CURVE MATCH OF WATER INJECTION
1 M THICK LOW K ZONE AT MID-FORMATION

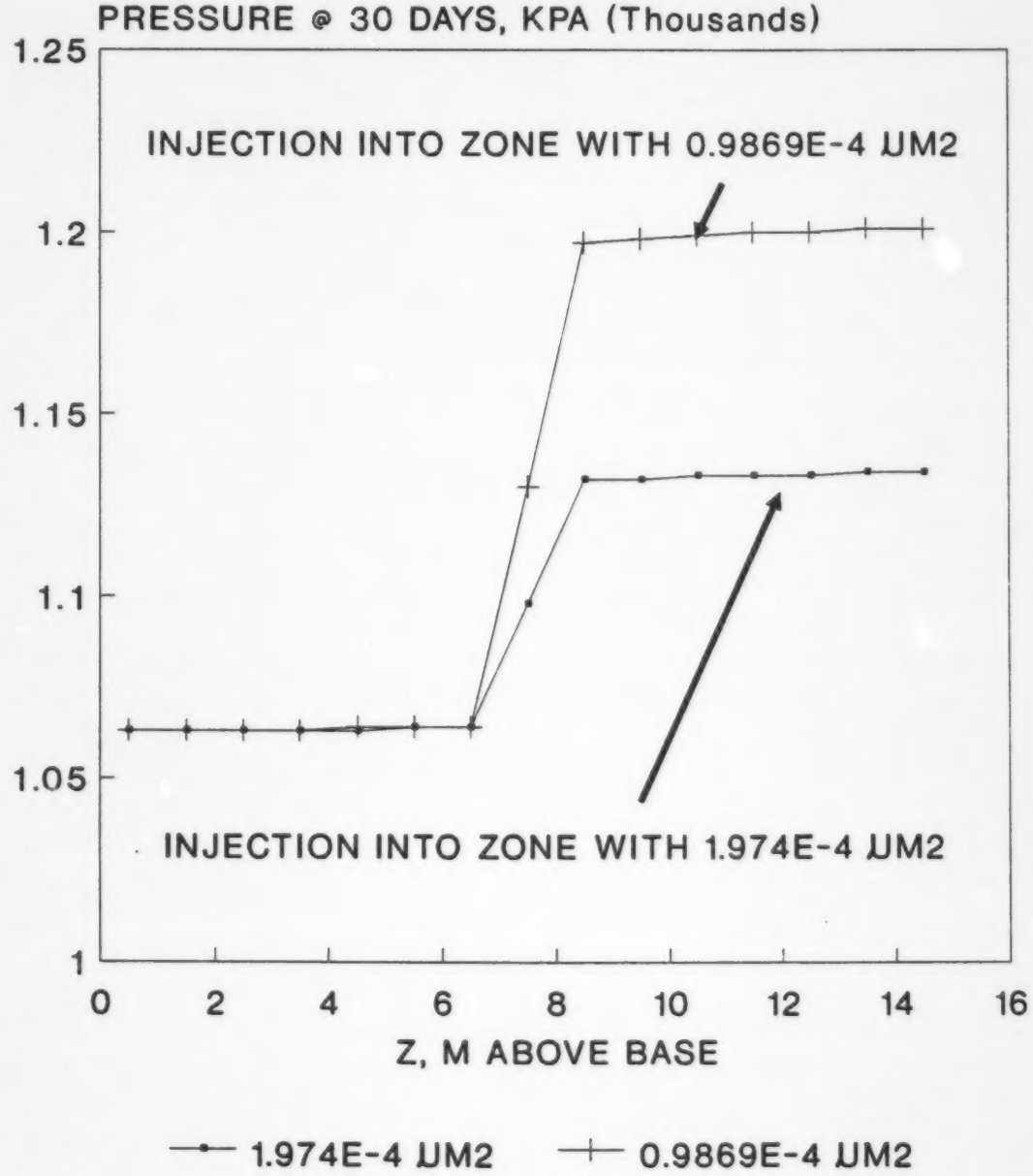


—— 1 PH.TYPE CURVE + 1 PH.MODEL DATA

OFFSET PRESSURES AVERAGED ARITHMETICALLY

FIGURE M - 1

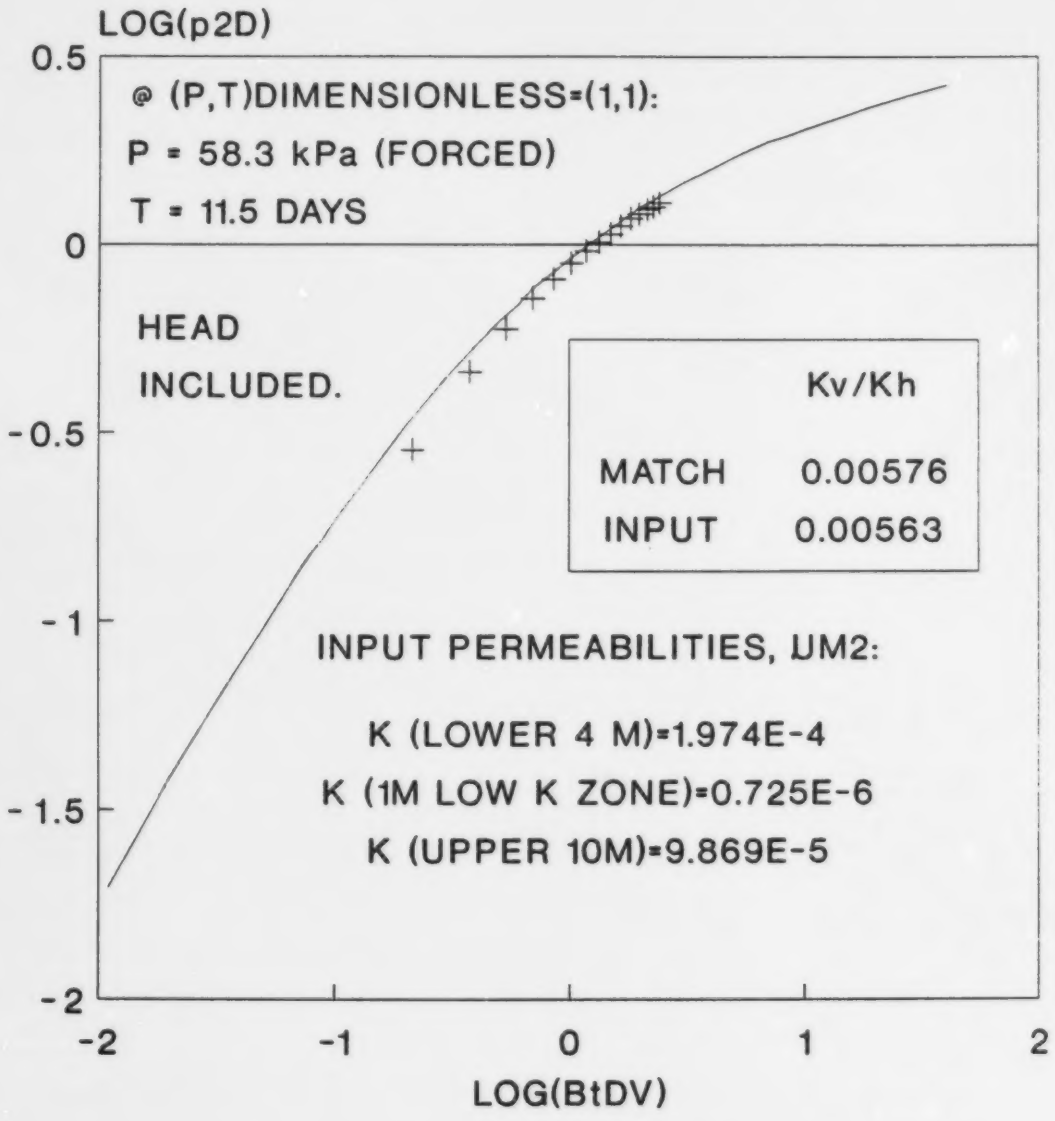
VERTICAL PRESSURE PROFILES @ OFFSET
LOW K ZONE @ MID-FORMATION



WATER INJECTION.

FIGURE M - 2

EE & A CURVE MATCH OF WATER INJECTION
1 M THICK LOW K ZONE 30% UP FROM BASE

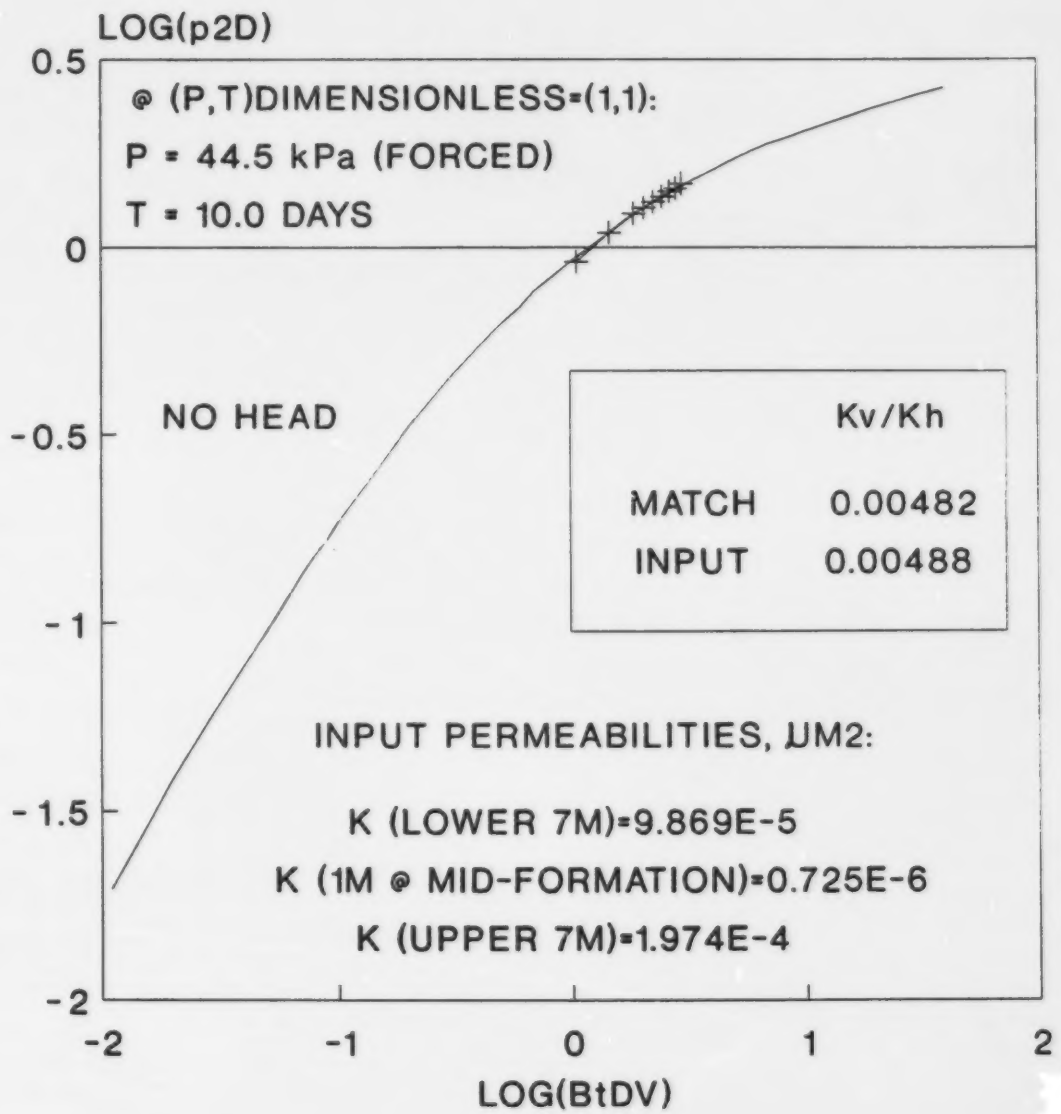


—— 1 PH.TYPE CURVE + 1 PH.MODEL DATA

OFFSET PRESSURES AVERAGED ARITHMETICALLY

FIGURE M - 3

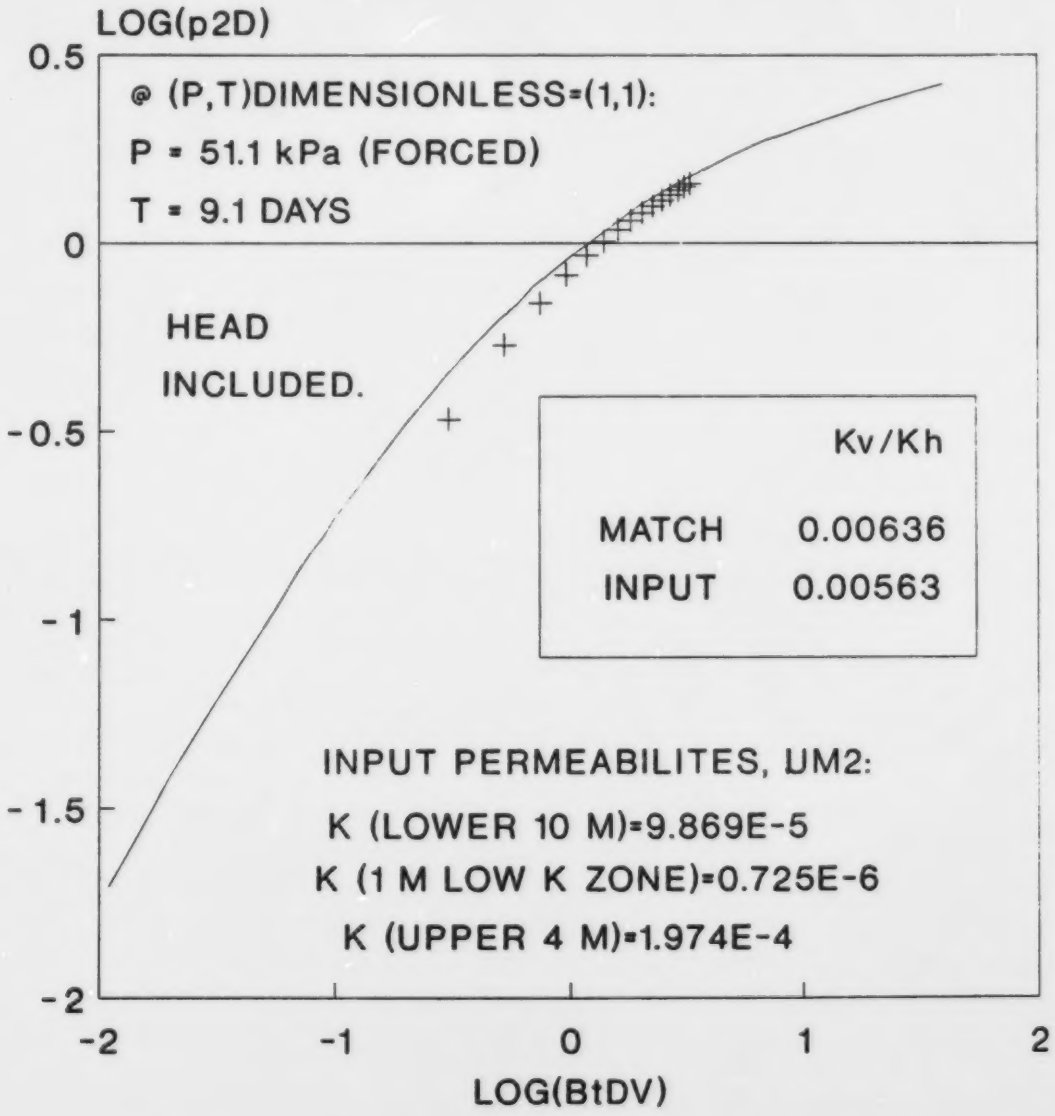
EE & A CURVE MATCH OF WATER INJECTION
1 M THICK LOW K ZONE AT MID-FORMATION



PERMEABILITY-WEIGHTED OFFSET PRESSURES

FIGURE M - 4

EE & A CURVE MATCH OF WATER INJECTION
1 M THICK LOW K ZONE 70% UP FROM BASE

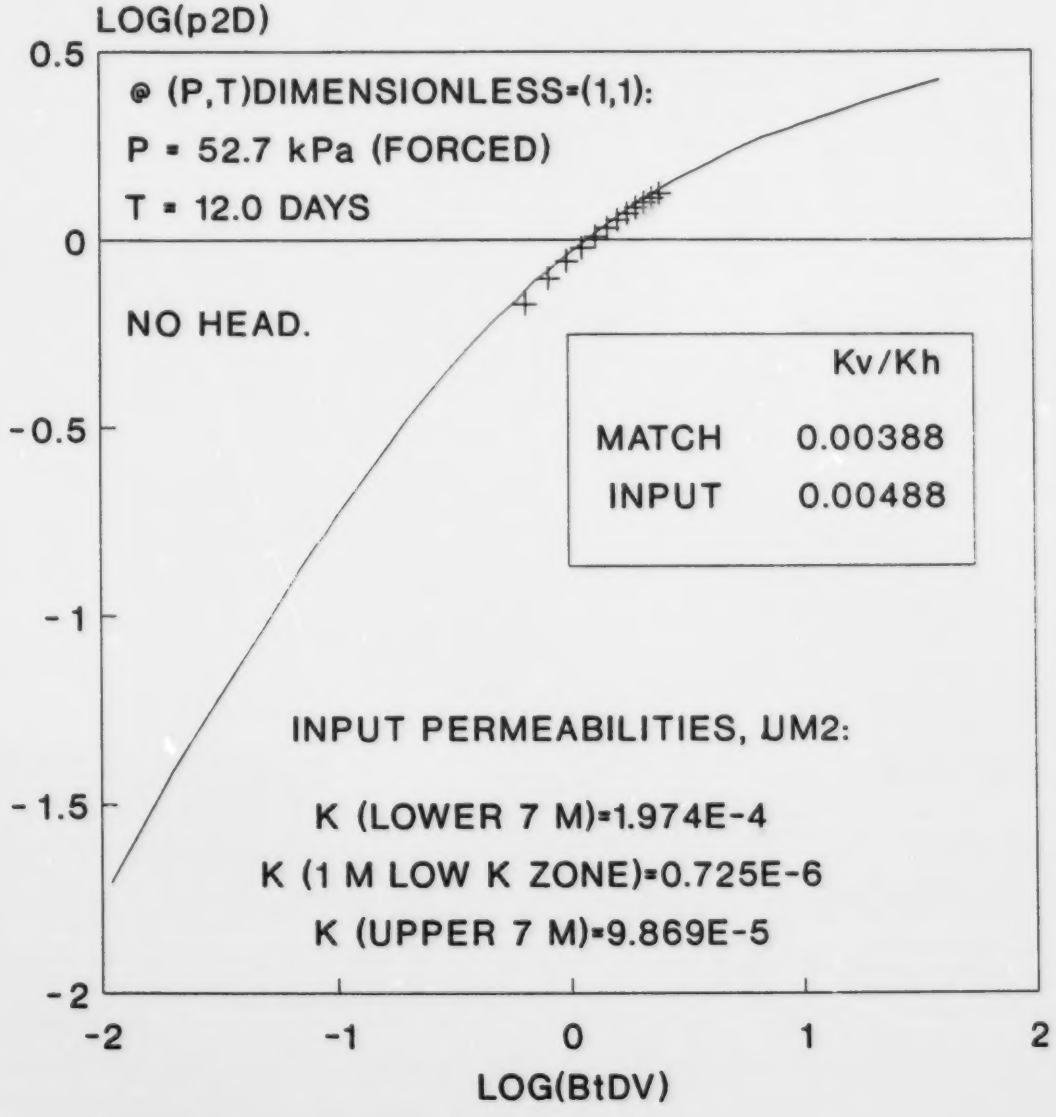


—— 1 PH.TYPE CURVE + 1 PH.MODEL DATA

PERMEABILITY-WEIGHTED OFFSET PRESSURES

FIGURE M - 5

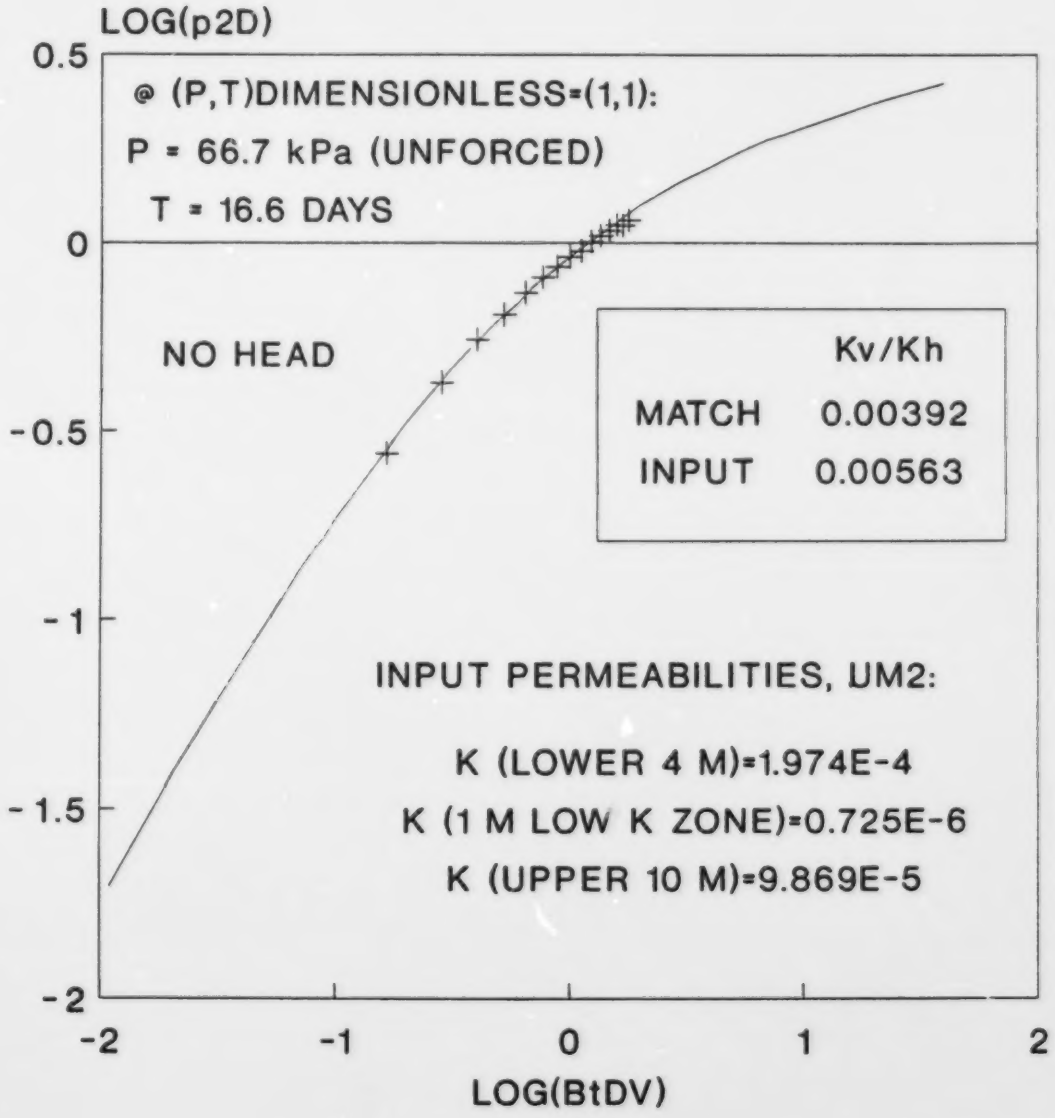
EE & A CURVE MATCH OF WATER INJECTION
1 M THICK LOW K ZONE @ MID-FORMATION



OFFSET PRESSURES AVERAGED ARITHMETICALLY

FIGURE M - 6

EE & A CURVE MATCH OF GAS INJECTION
1 M THICK LOW K ZONE 30% UP FROM BASE

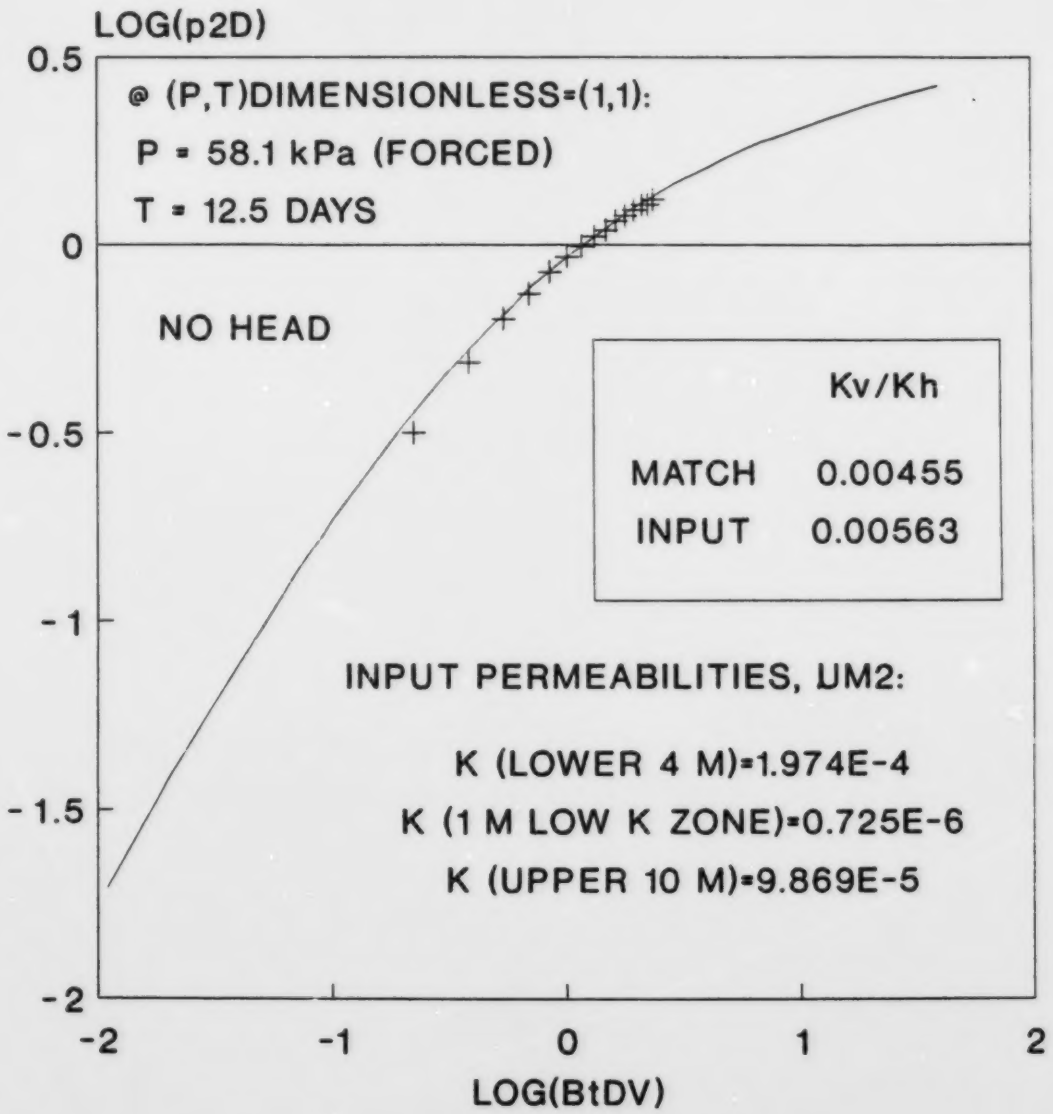


—— 1 PH.TYPE CURVE + 2 PH.MODEL DATA

OFFSET PRESSURES AVERAGED ARITHMETICALLY

FIGURE M - 7

EE & A CURVE MATCH OF GAS INJECTION
1 M THICK LOW K ZONE 30% UP FROM BASE



OFFSET PRESSURES AVERAGED ARITHMETICALLY

FIGURE M - 8

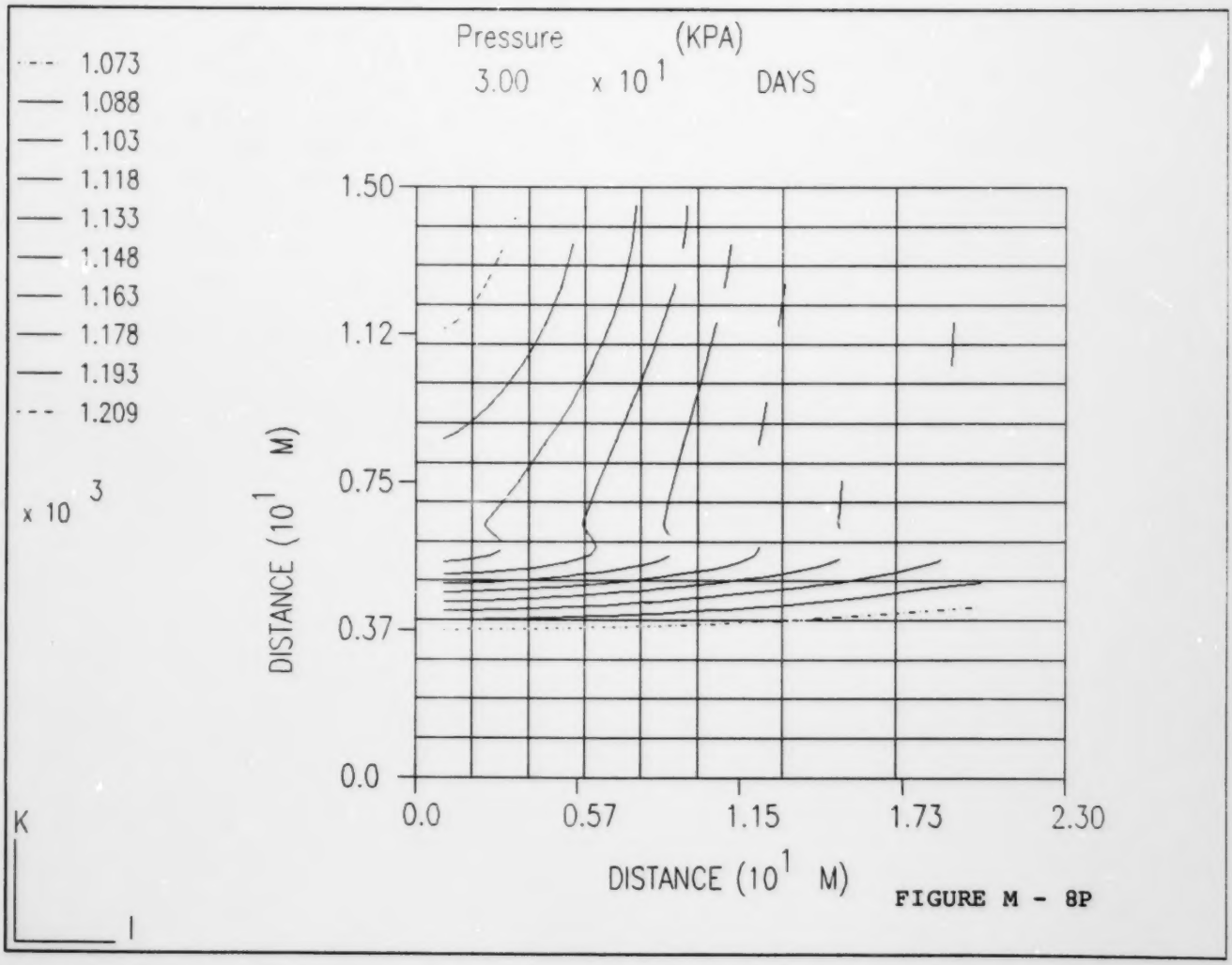
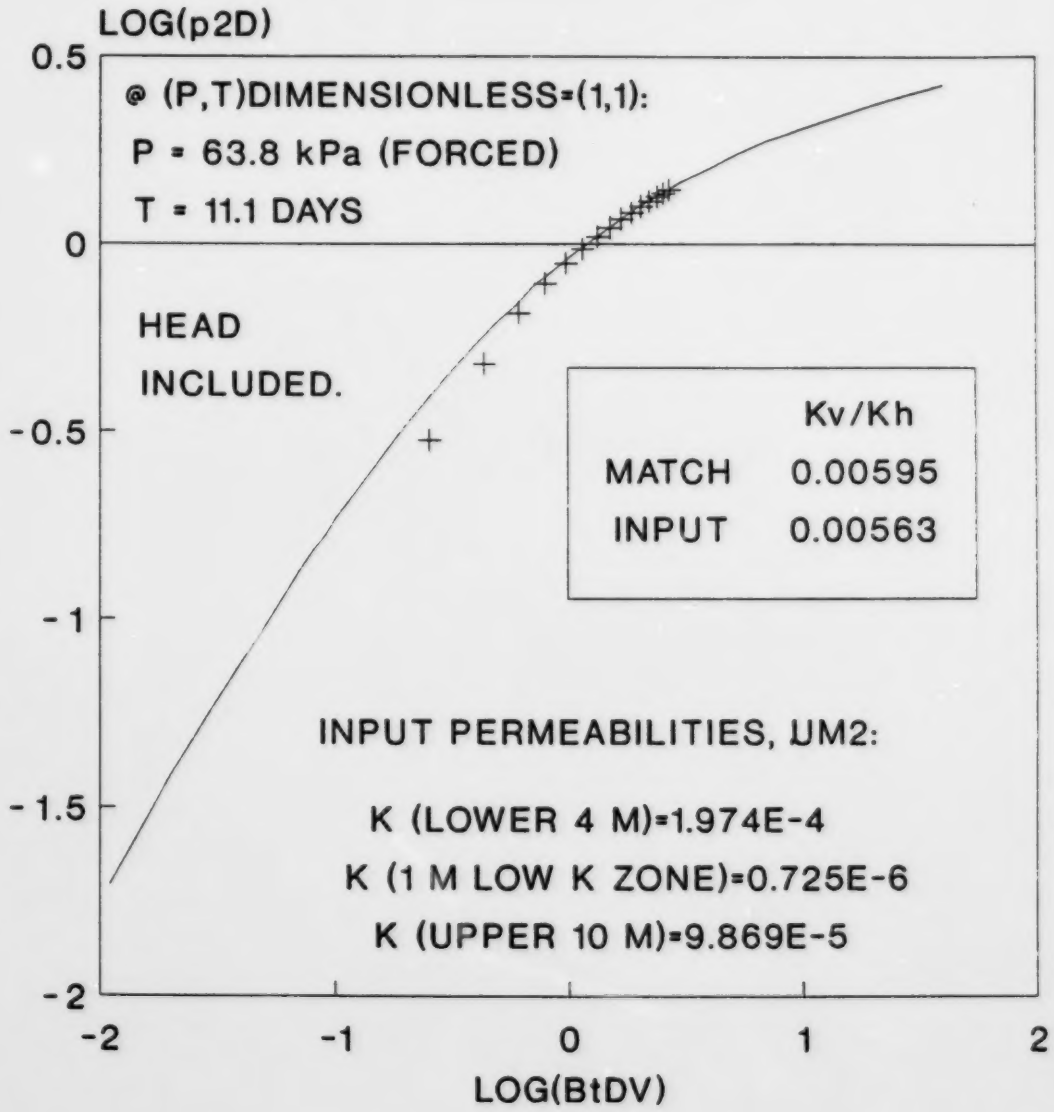

Pressure (KPA)
3.00 x 10 1 DAYS
--- 1.073
— 1.088
— 1.103
— 1.118
— 1.133
— 1.148
— 1.163
— 1.178
— 1.193
--- 1.209
x 10 3
1.50
1.12
0.75
0.37
0.0
DISTANCE (10 1 M)
0.0
0.57
1.15
1.73
2.30
DISTANCE (10 1 M)
K
I

FIGURE M - 8P

EE & A CURVE MATCH OF GAS INJECTION
1 M THICK LOW K ZONE 30% UP FROM BASE



—— 1 PH.TYPE CURVE + 2 PH.MODEL DATA

OFFSET PRESSURES AVERAGED ARITHMETICALLY

FIGURE M - 9

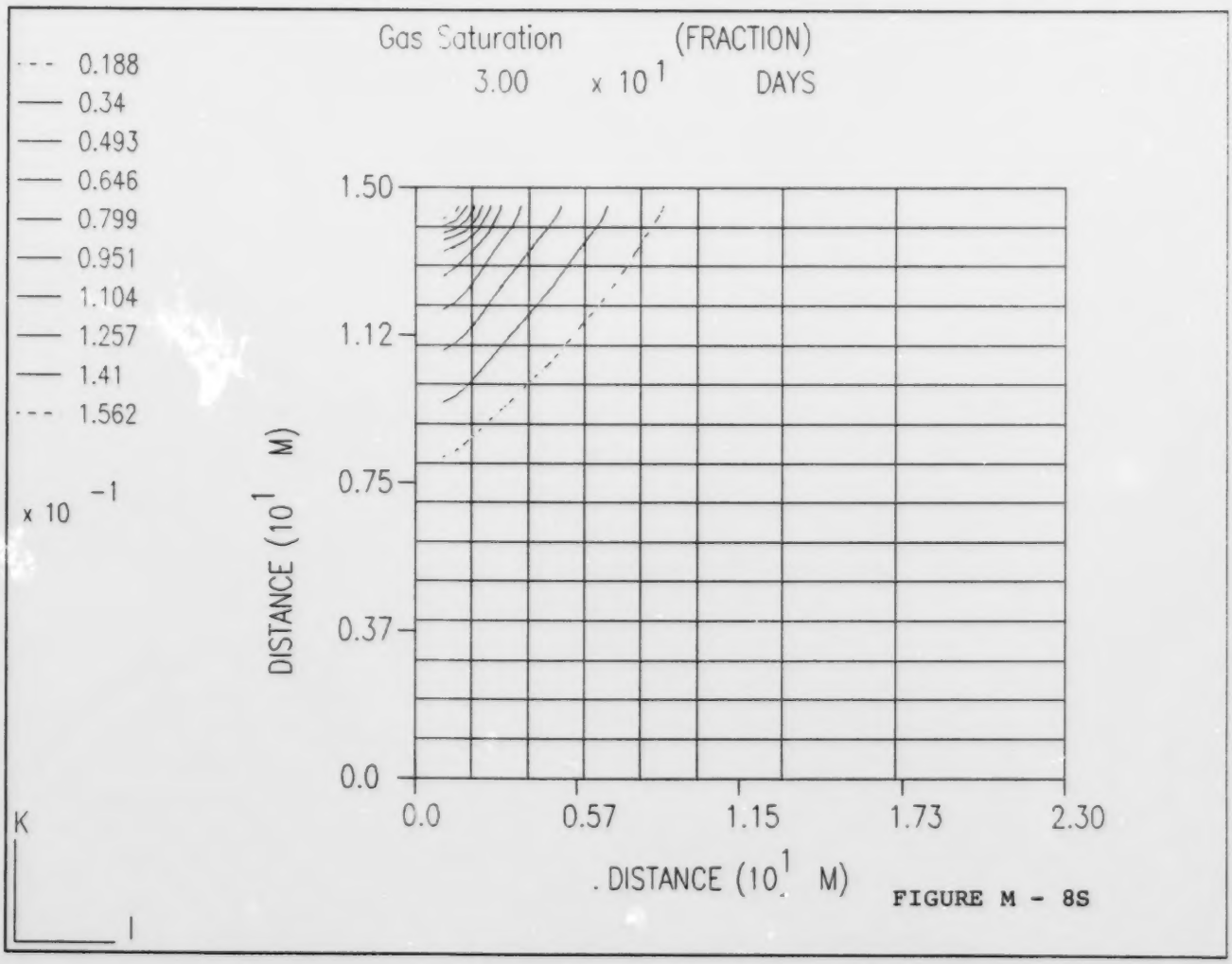

Gas Saturation (FRACTION)
3.00 x 10 1 DAYS
0.188
0.34
0.493
0.646
0.799
0.951
1.104
1.257
1.41
1.562
x 10 -1
1.50
1.12
0.75
0.37
0.0
DISTANCE (10 1 M)
0.0
0.57
1.15
1.73
2.30
. DISTANCE (10 1 M)
K
I

FIGURE M - 8S

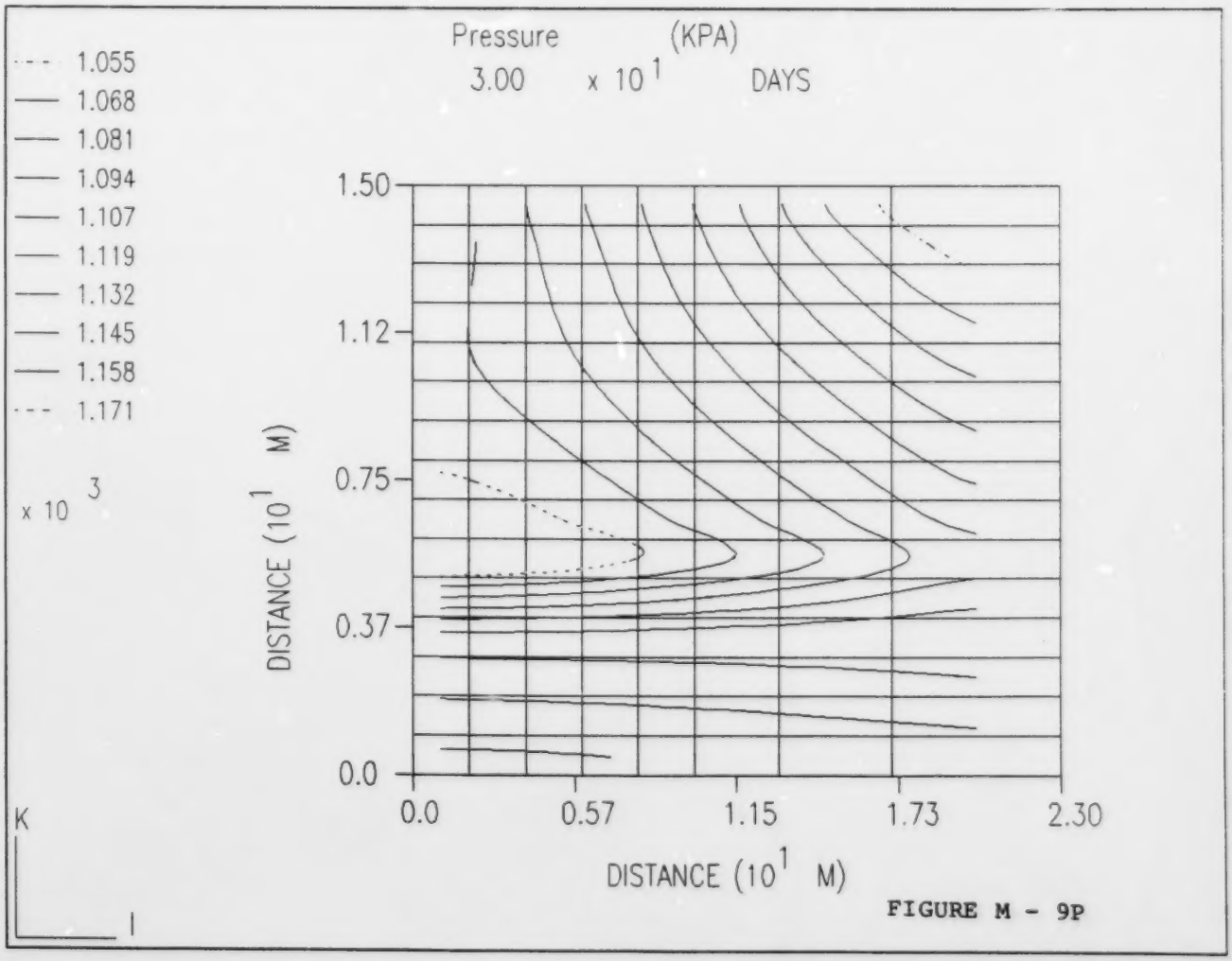

Pressure (KPA)
3.00 x 10 1 DAYS
1.055
1.068
1.081
1.094
1.107
1.119
1.132
1.145
1.158
1.171
x 10 3
1.50
1.12
0.75
0.37
0.0
DISTANCE (10 1 M)
0.0
0.57
1.15
1.73
2.30
DISTANCE (10 1 M)
K
I

FIGURE M - 9P

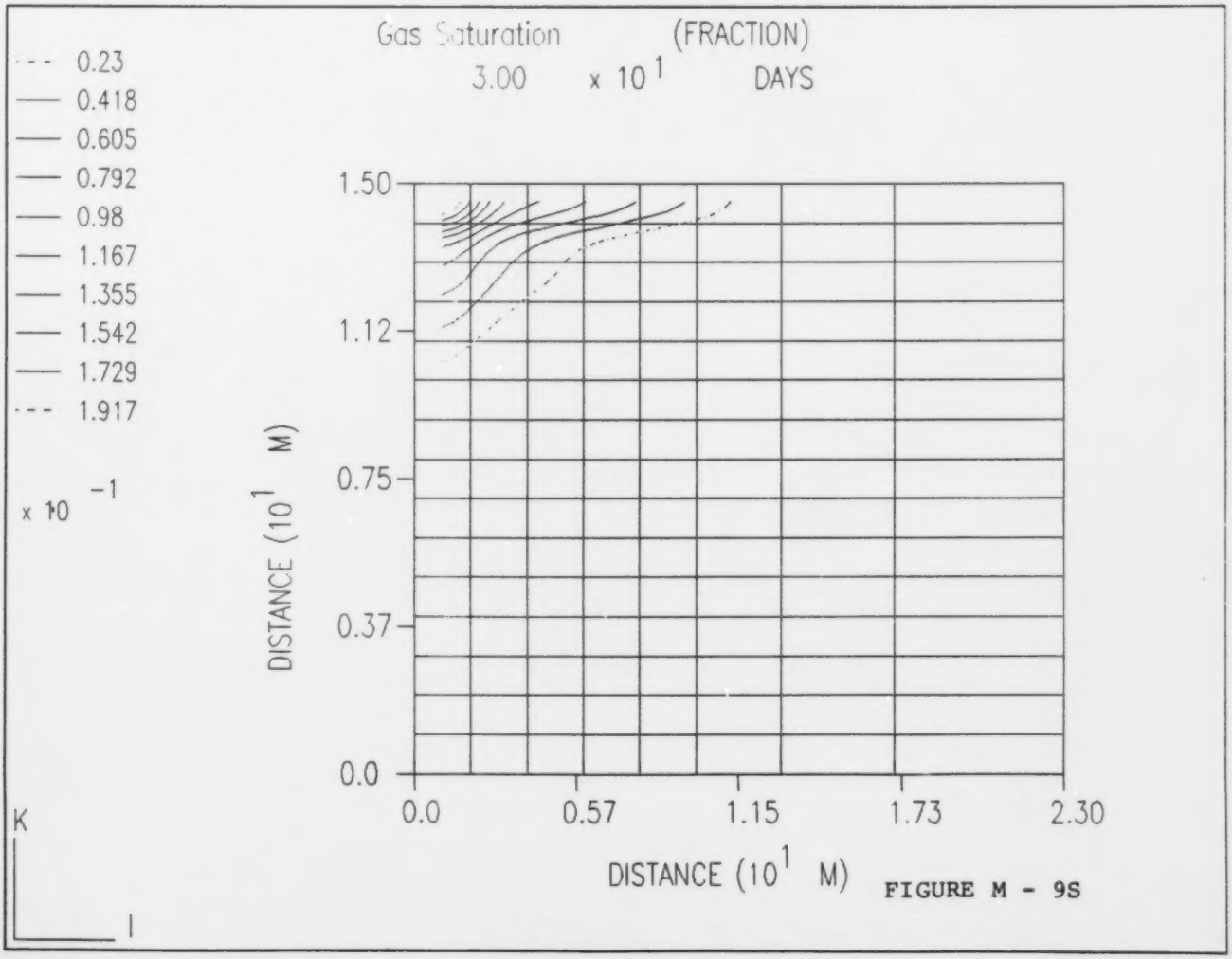
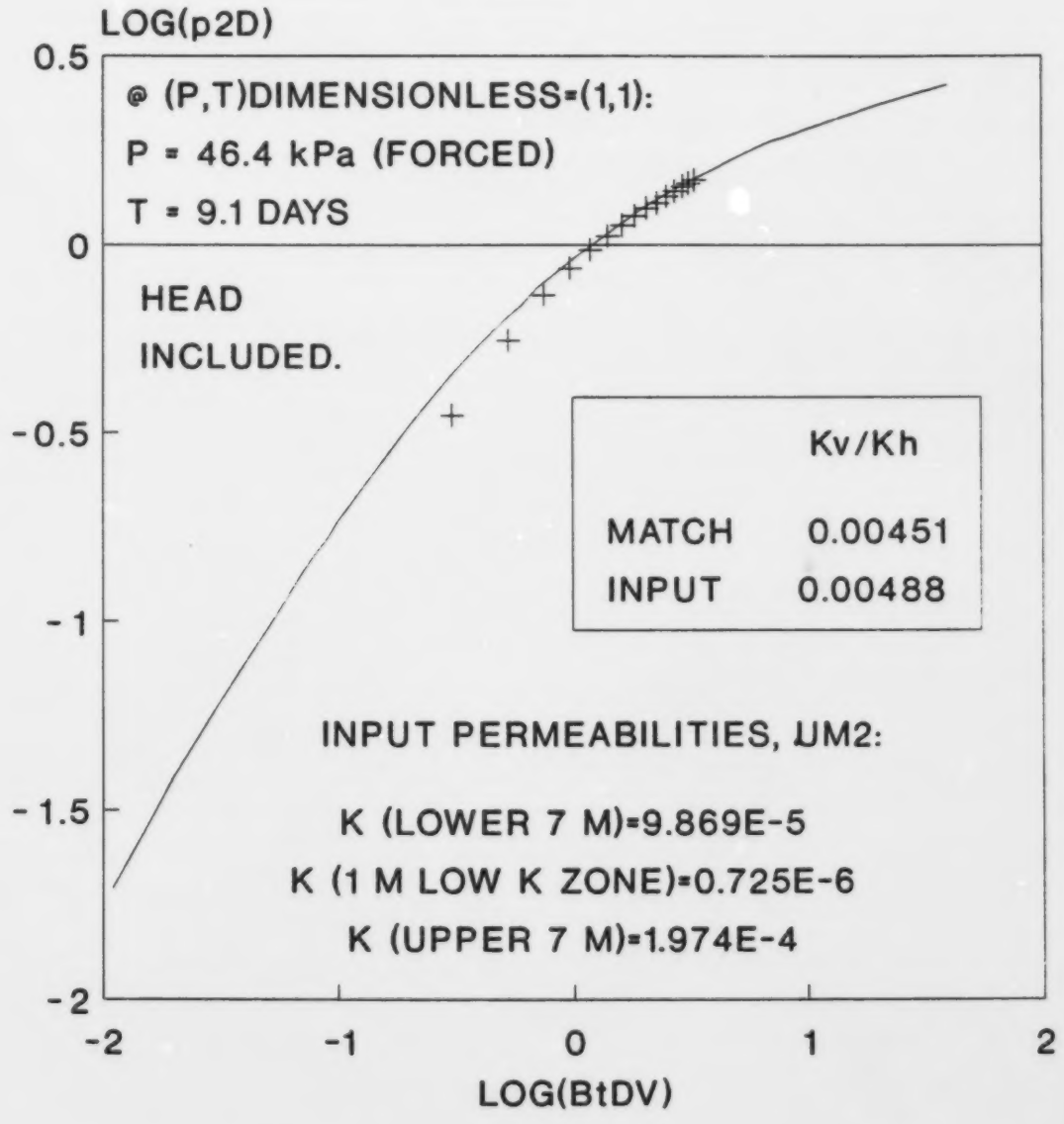

Gas Saturation (FRACTION)
3.00 x 10 1 DAYS
0.23
0.418
0.605
0.792
0.98
1.167
1.355
1.542
1.729
1.917
x 10 -1
1.50
1.12
0.75
0.37
0.0
DISTANCE (10 1 M)
0.0
0.57
1.15
1.73
2.30
DISTANCE (10 1 M)
K
I

FIGURE M - 9S

EE & A CURVE MATCH OF GAS INJECTION
1 M THICK LOW K ZONE @ MID-FORMATION



—— 1 PH.TYPE CURVE + 2 PH.MODEL DATA

PERMEABILITY-WEIGHTED OFFSET PRESSURES

FIGURE M - 10

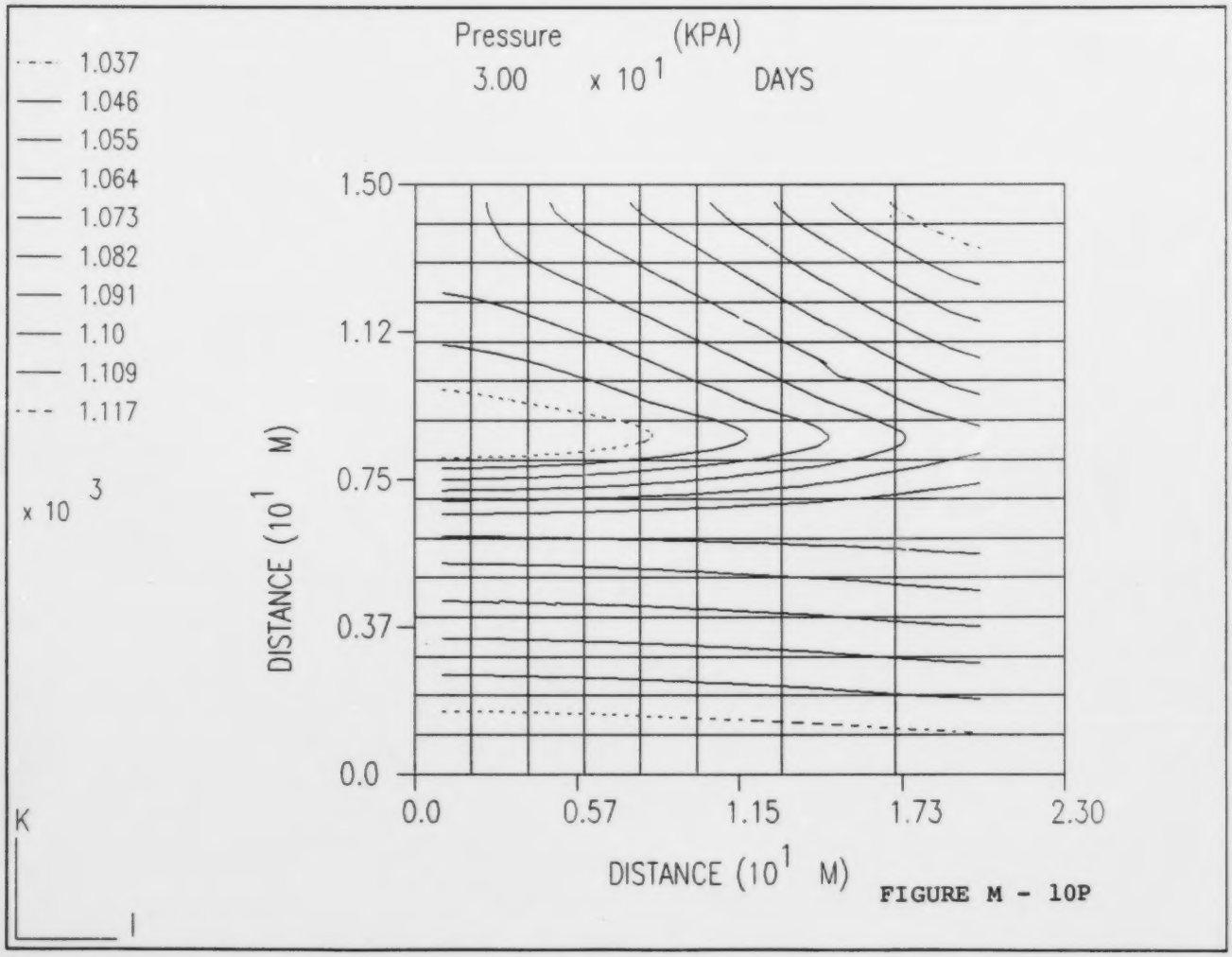

Pressure (KPA)
3.00 x 10 1 DAYS
1.037
1.046
1.055
1.064
1.073
1.082
1.091
1.10
1.109
1.117
x 10 3
1.50
1.12
0.75
0.37
0.0
DISTANCE (10 1 M)
0.0
0.57
1.15
1.73
2.30
DISTANCE (10 1 M)
K
I

FIGURE M - 10P

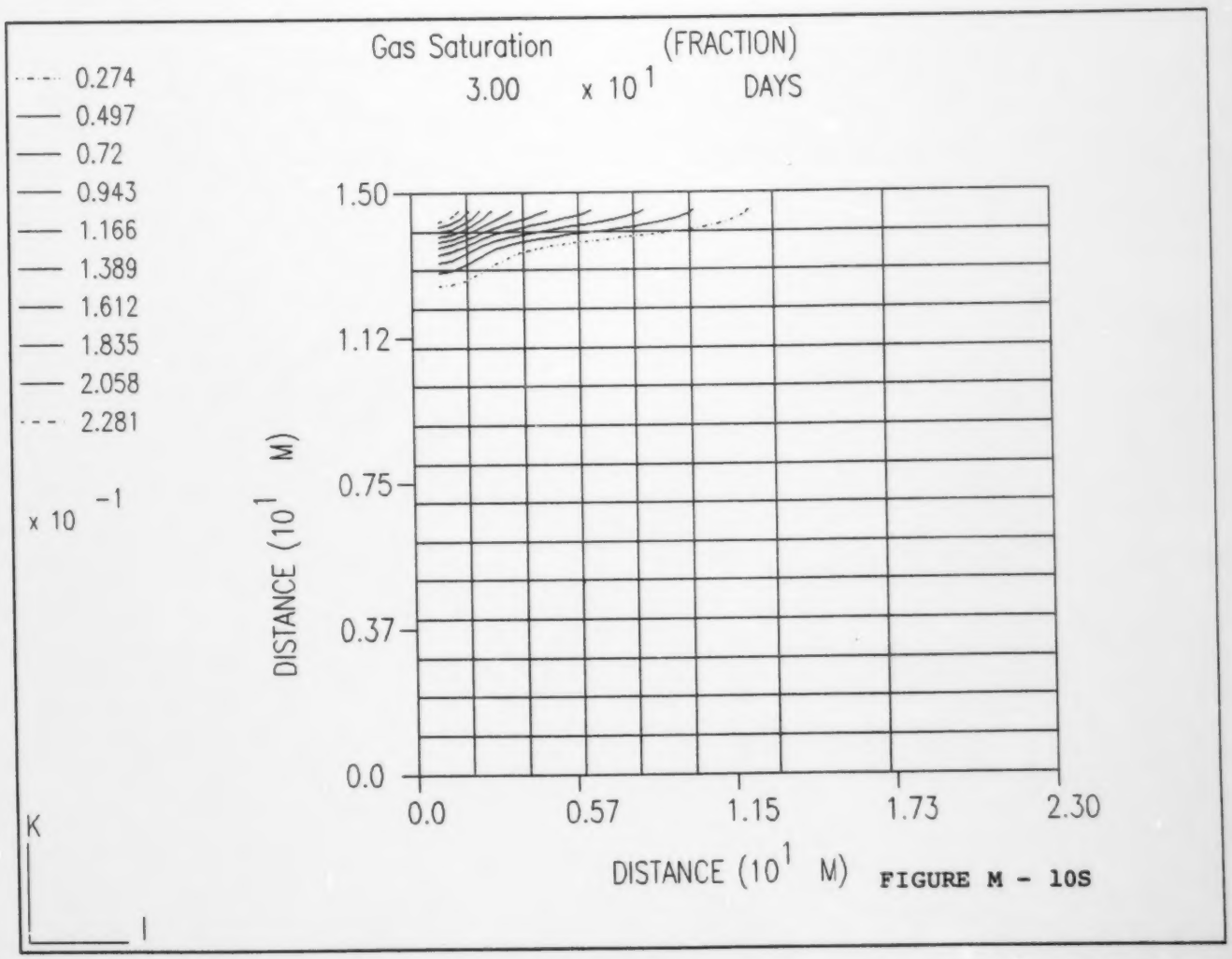
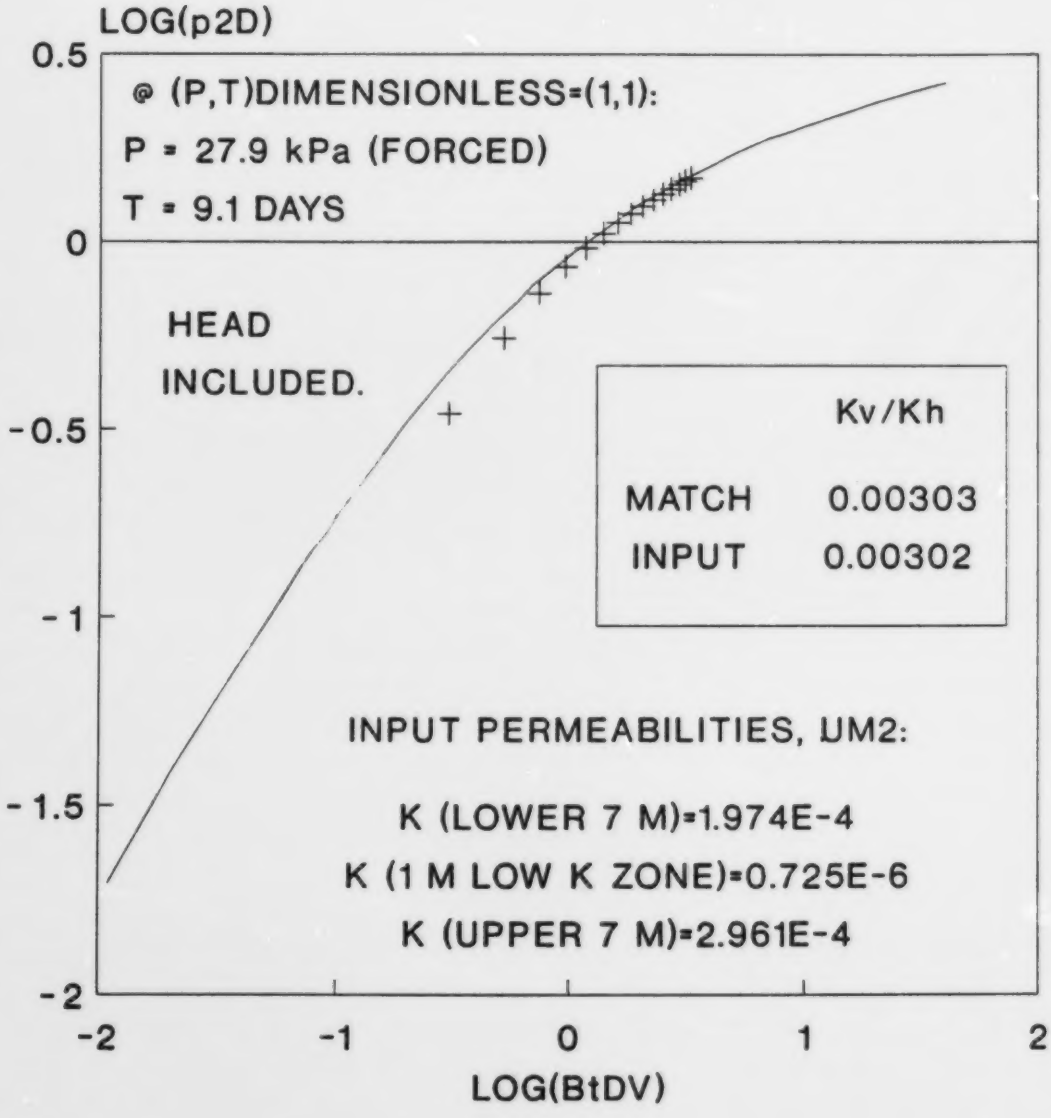

Gas Saturation (FRACTION)
3.00 x 10^1 DAYS
0.274
0.497
0.72
0.943
1.166
1.389
1.612
1.835
2.058
2.281
x 10^-1
1.50
1.12
0.75
0.37
0.0
DISTANCE (10^1 M)
0.0
0.57
1.15
1.73
2.30
DISTANCE (10^1 M)
K
I

FIGURE M - 10S

EE & A CURVE MATCH OF GAS INJECTION
1 M THICK LOW K ZONE @ MID-FORMATION



PERMEABILITY-WEIGHTED OFFSET PRESSURES

FIGURE M - 11

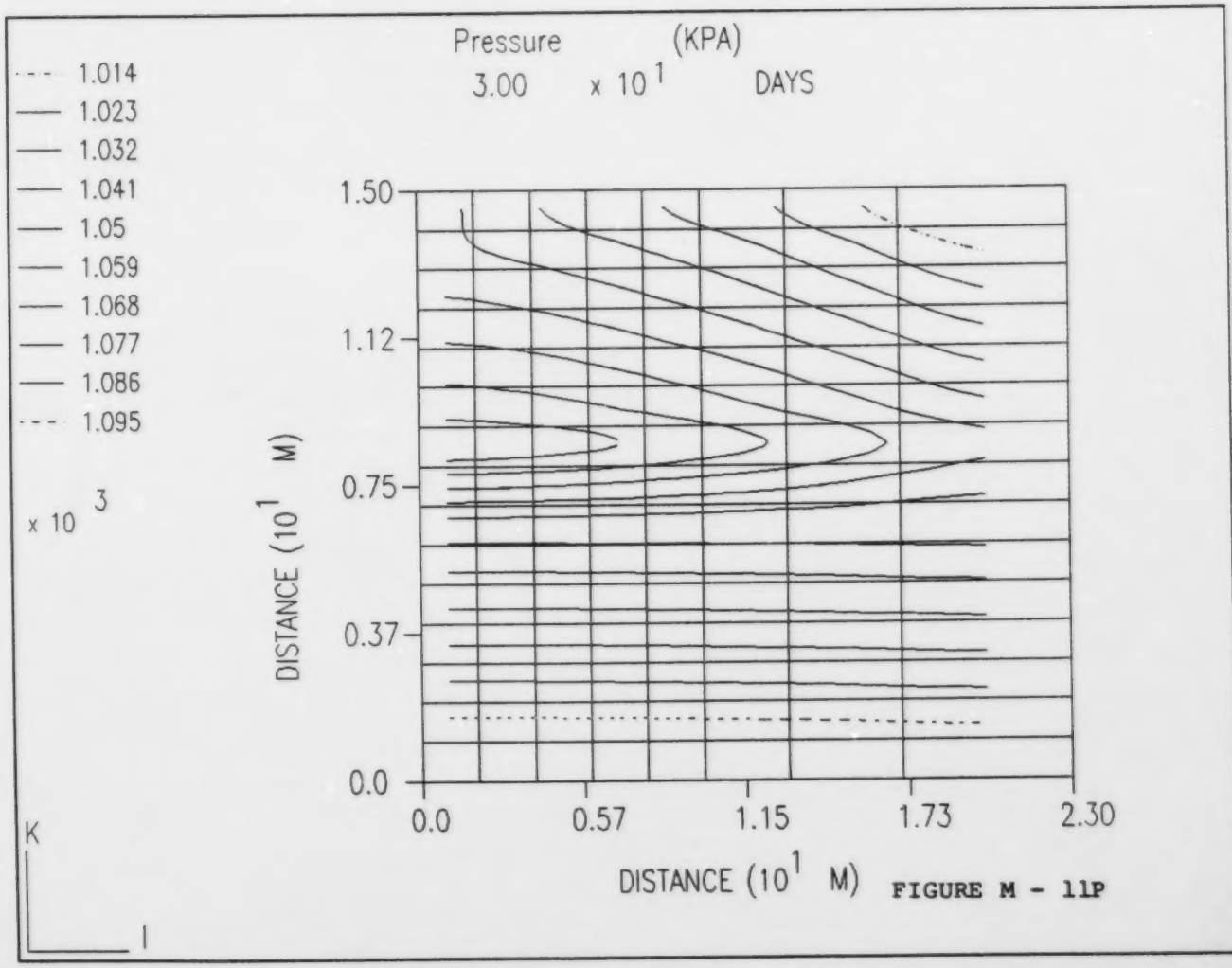

Pressure (KPA)
3.00 x 10 1 DAYS
1.014
1.023
1.032
1.041
1.05
1.059
1.068
1.077
1.086
1.095
x 10 3
1.50
1.12
0.75
0.37
0.0
DISTANCE (10 1 M)
0.0
0.57
1.15
1.73
2.30
DISTANCE (10 1 M)
K
I

FIGURE M - 11P

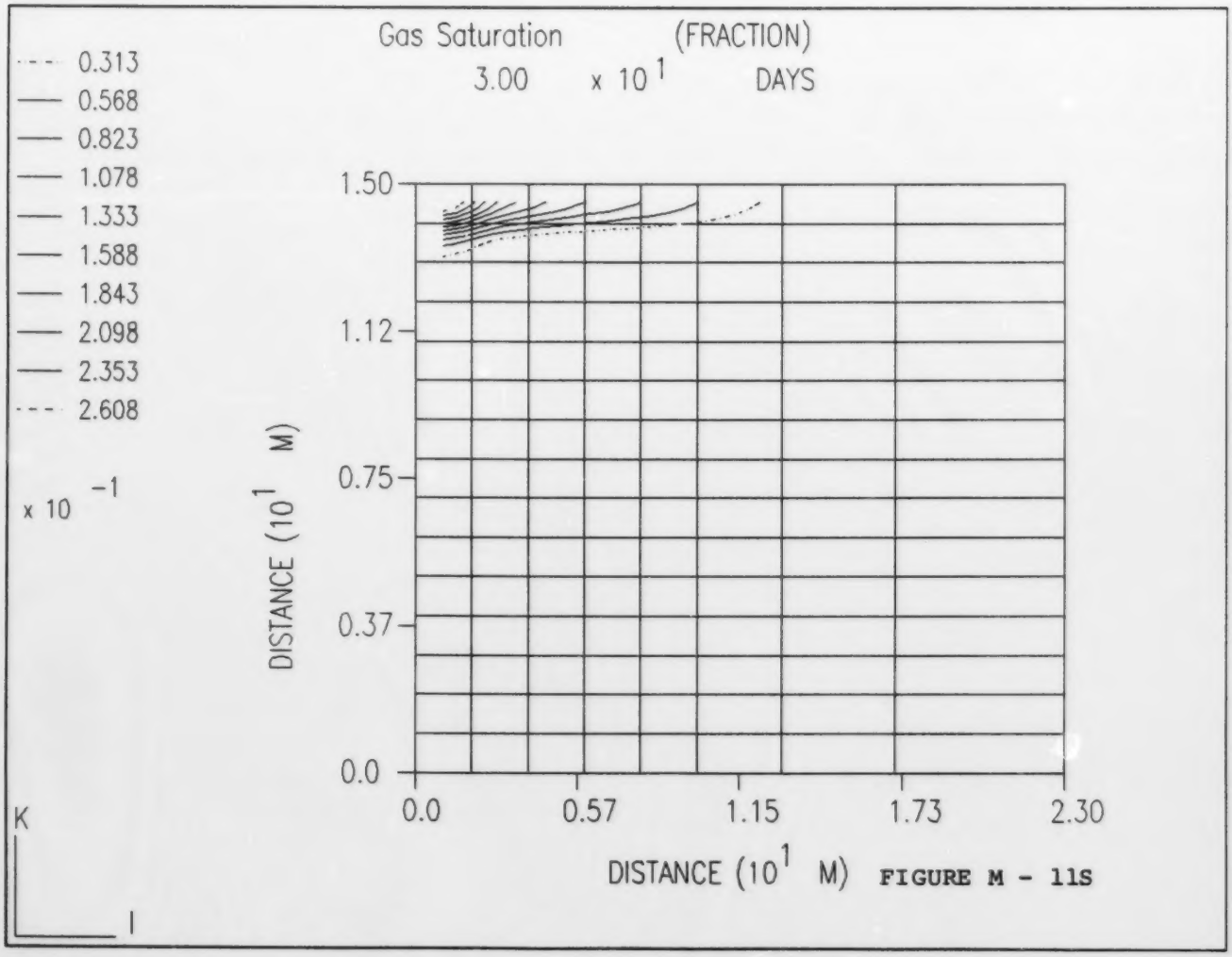
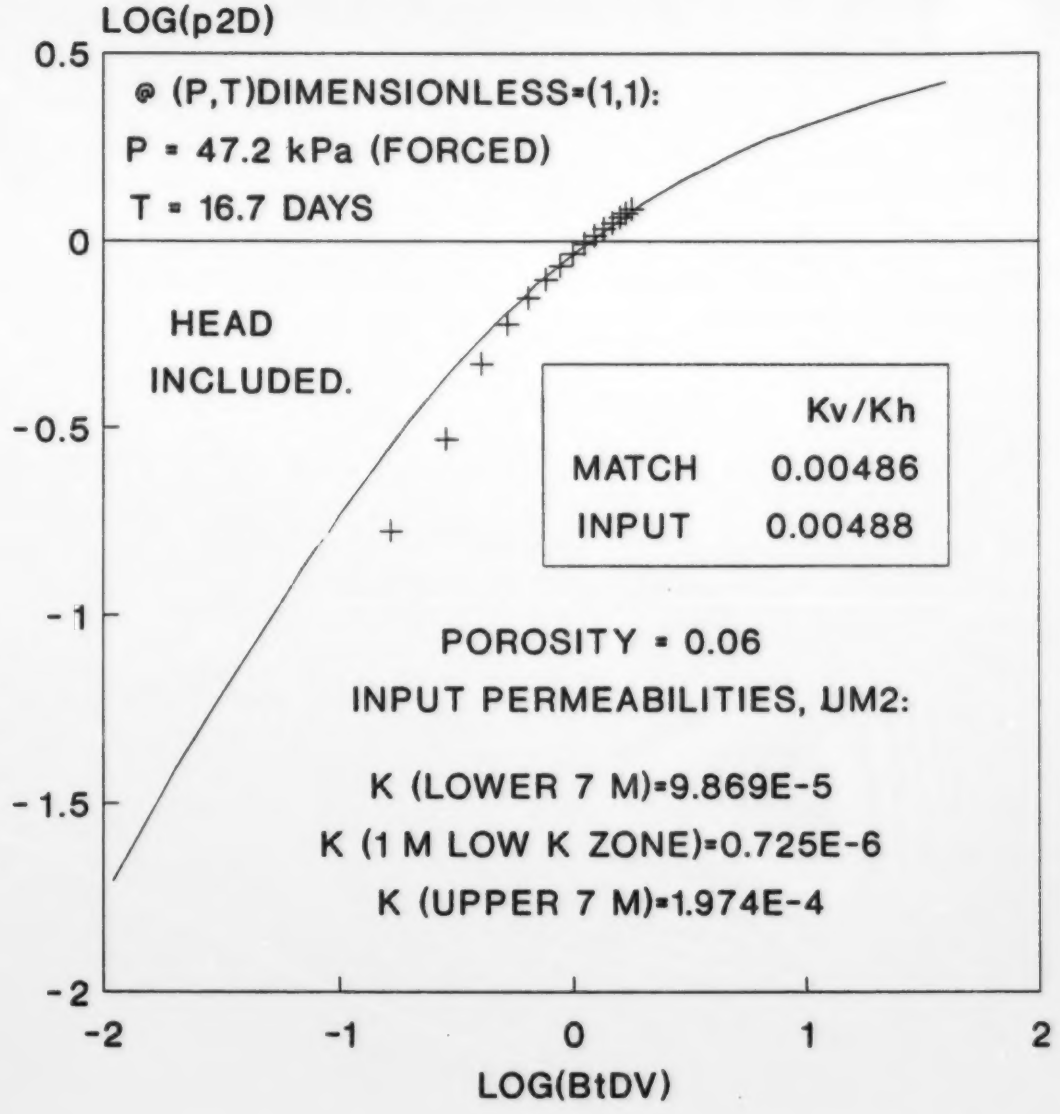

Gas Saturation (FRACTION)
3.00 x 10 1 DAYS
0.313
0.568
0.823
1.078
1.333
1.588
1.843
2.098
2.353
2.608
x 10 -1
1.50
1.12
0.75
0.37
0.0
DISTANCE (10 1 M)
0.0
0.57
1.15
1.73
2.30
DISTANCE (10 1 M)
K
I

FIGURE M - 11S

EE & A CURVE MATCH OF GAS INJECTION
1 M THICK LOW K ZONE @ MID-FORMATION



—— 1 PH.TYPE CURVE + 2 PH.MODEL DATA

PERMEABILITY-WEIGHTED OFFSET PRESSURES

FIGURE M - 12

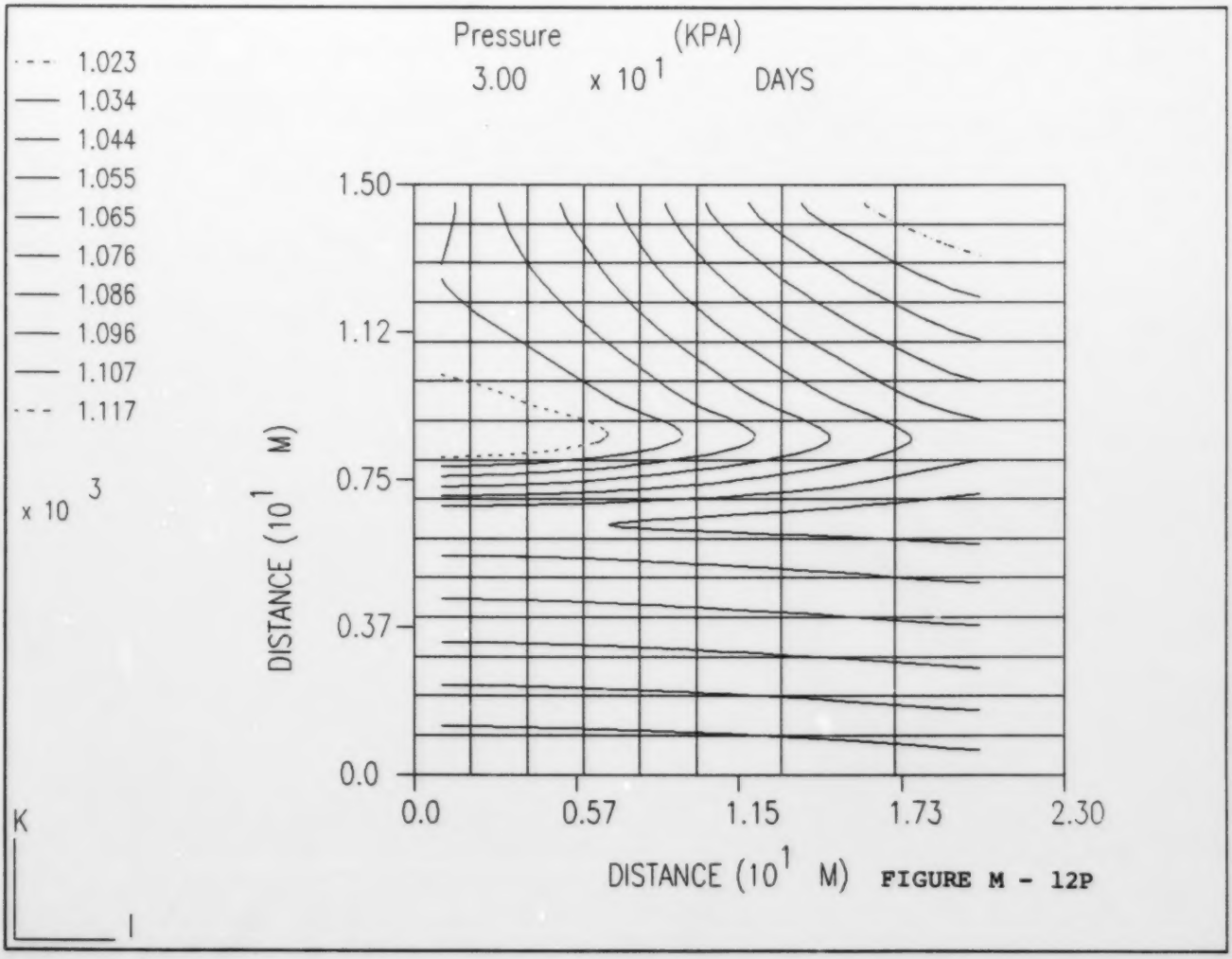

Pressure (KPA)
3.00 x 10 1 DAYS
1.023
1.034
1.044
1.055
1.065
1.076
1.086
1.096
1.107
1.117
x 10 3
1.50
1.12
0.75
0.37
0.0
DISTANCE (10 1 M)
0.0
0.57
1.15
1.73
2.30
DISTANCE (10 1 M)
K
I

FIGURE M - 12P

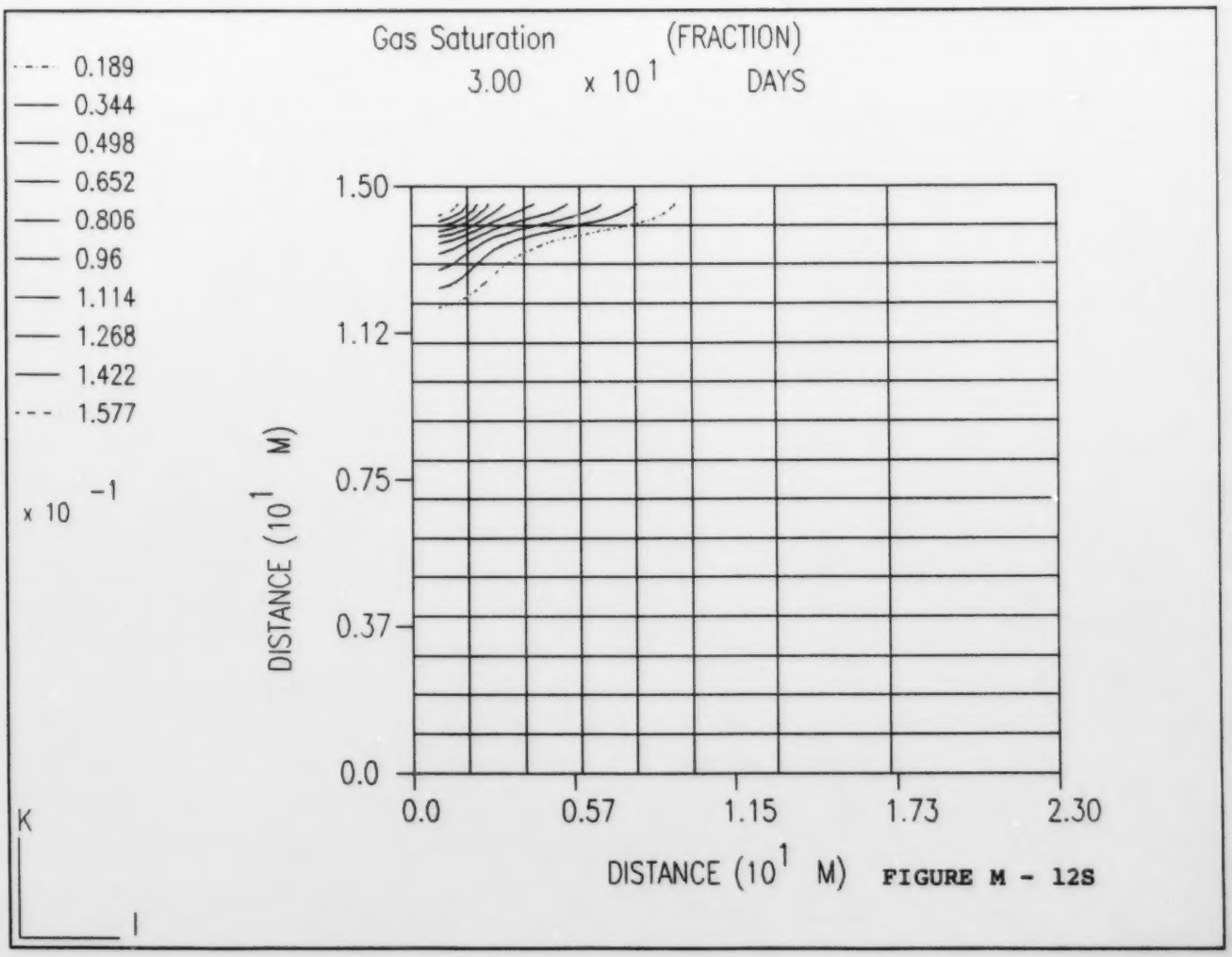
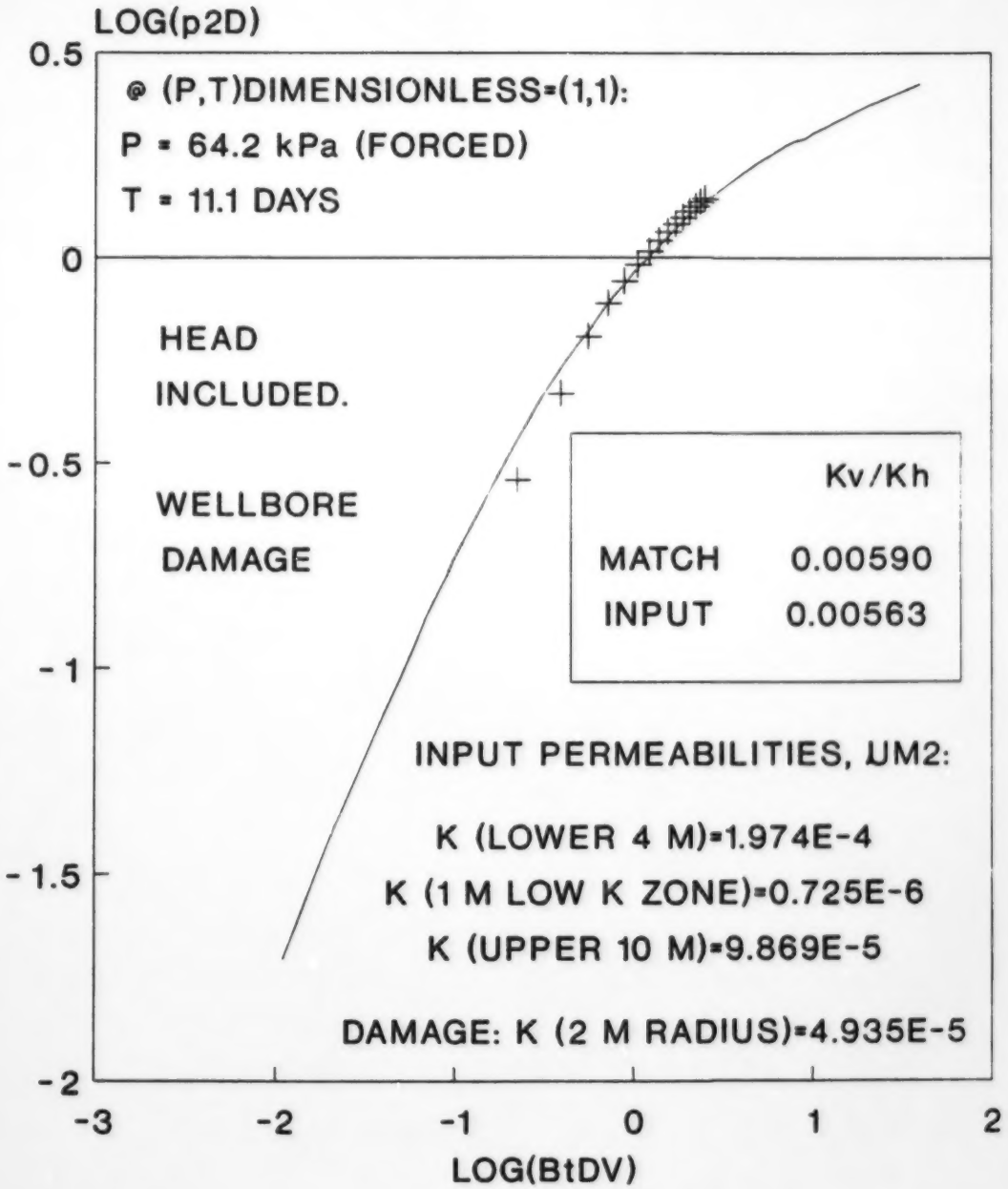

Gas Saturation (FRACTION)
3.00 x 10 1 DAYS
0.189
0.344
0.498
0.652
0.806
0.96
1.114
1.268
1.422
1.577
x 10 -1
1.50
1.12
0.75
0.37
0.0
DISTANCE (10 1 M)
0.0
0.57
1.15
1.73
2.30
DISTANCE (10 1 M)
K
I

FIGURE M - 12S

EE&A CURVE MATCH OF GAS INJECTION
1 M THICK LOW K ZONE 30% UP FROM BASE



OFFSET PRESSURES AVERAGED ARITHMETICALLY

FIGURE M - 13

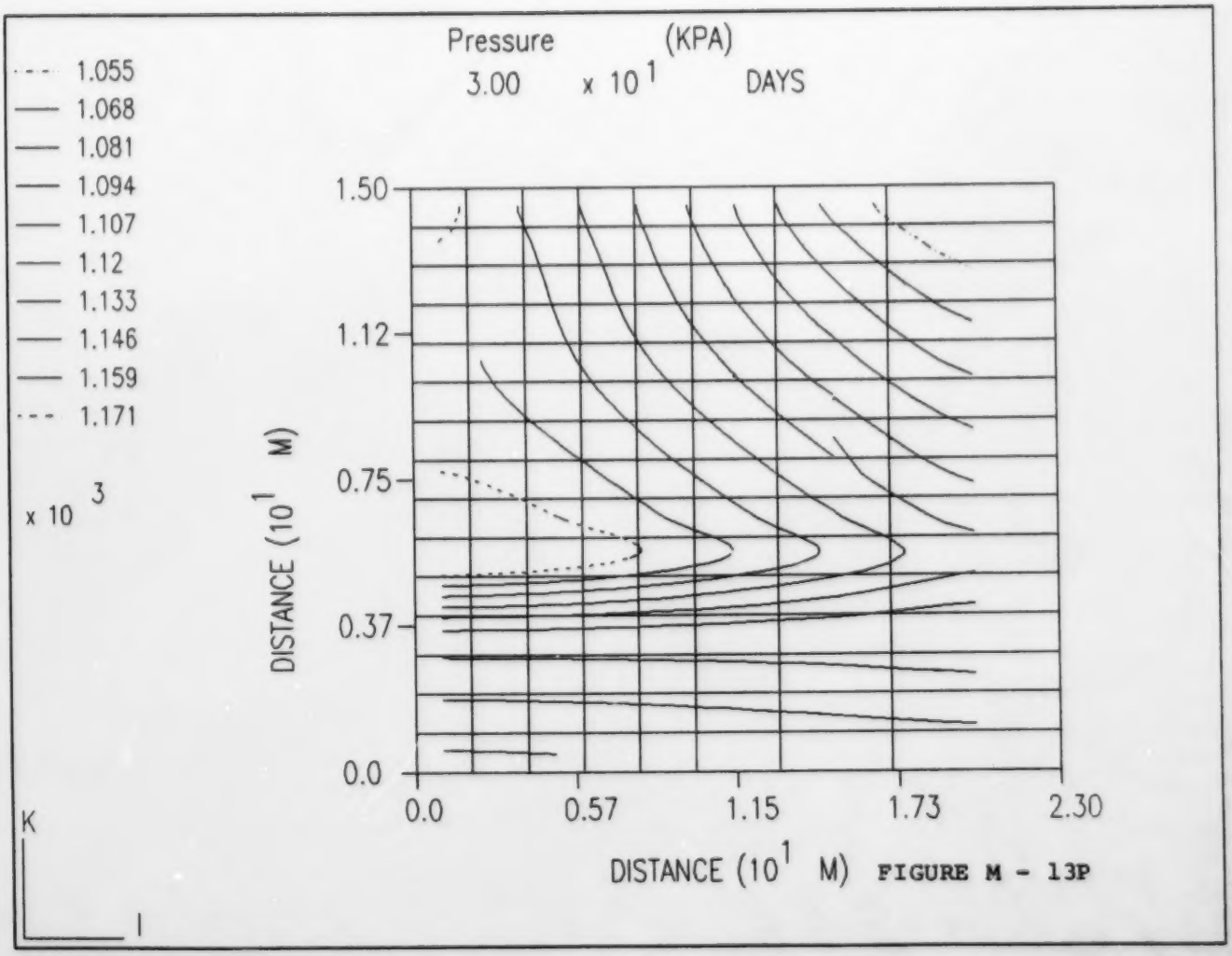

Pressure (KPA)
3.00 x 10 1 DAYS
1.055
1.068
1.081
1.094
1.107
1.12
1.133
1.146
1.159
1.171
x 10 3
1.50
1.12
0.75
0.37
0.0
DISTANCE (10 1 M)
0.0
0.57
1.15
1.73
2.30
DISTANCE (10 1 M)
K
I

FIGURE M - 13P

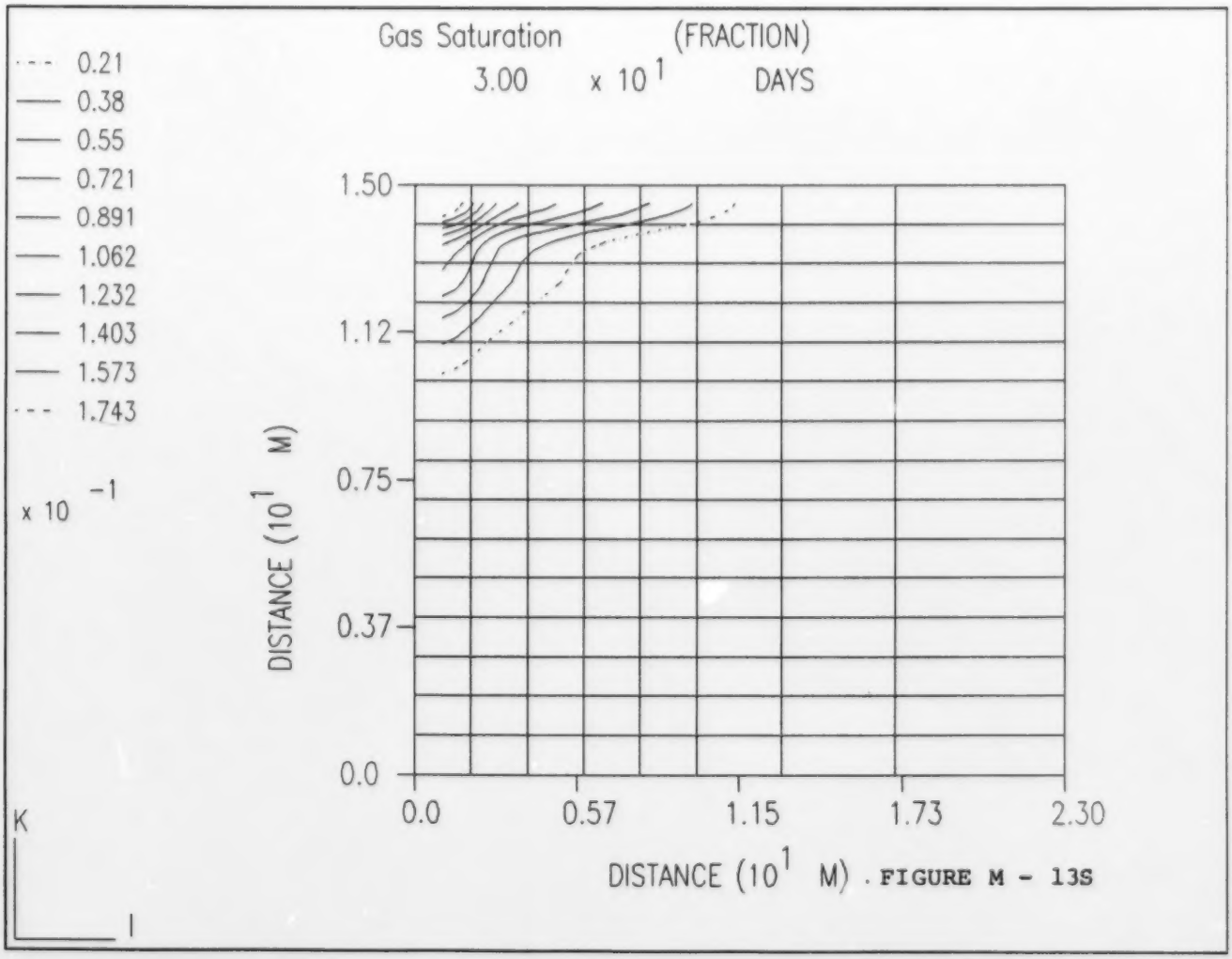
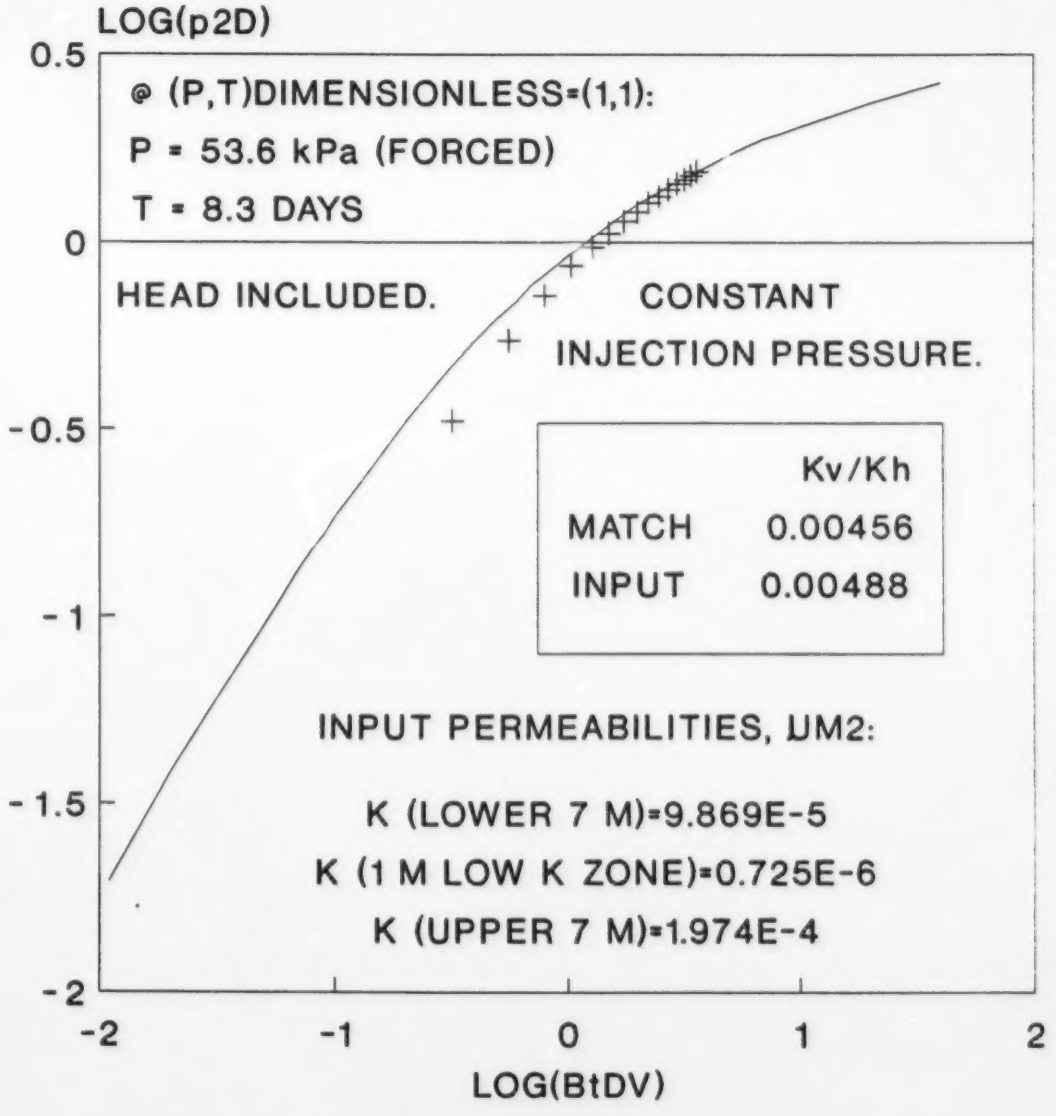

Gas Saturation (FRACTION)
3.00 x 10 1 DAYS
0.21
0.38
0.55
0.721
0.891
1.062
1.232
1.403
1.573
1.743
x 10 -1
1.50
1.12
0.75
0.37
0.0
DISTANCE (10 1 M)
0.0
0.57
1.15
1.73
2.30
DISTANCE (10 1 M)
K
I

FIGURE M - 13S

UPC

EE & A CURVE MATCH OF GAS INJECTION
1 M THICK LOW K ZONE @ MID-FORMATION



PERMEABILITY-WEIGHTED OFFSET PRESSURES

FIGURE M - 14

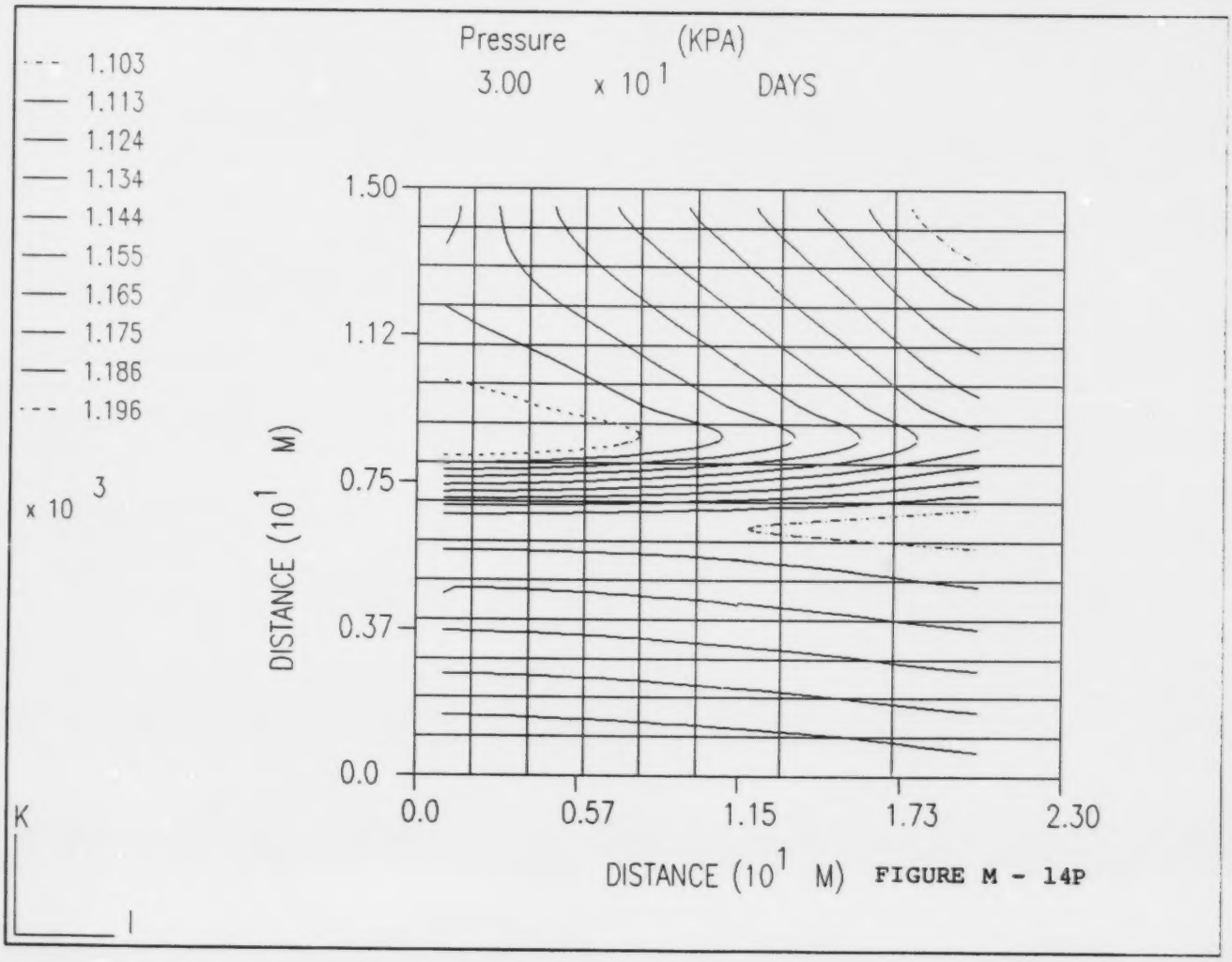

Pressure (KPA)
3.00 x 10 1 DAYS
1.103
1.113
1.124
1.134
1.144
1.155
1.165
1.175
1.186
1.196
x 10 3
1.50
1.12
0.75
0.37
0.0
DISTANCE (10 1 M)
0.0
0.57
1.15
1.73
2.30
DISTANCE (10 1 M)
K
I

FIGURE M - 14P

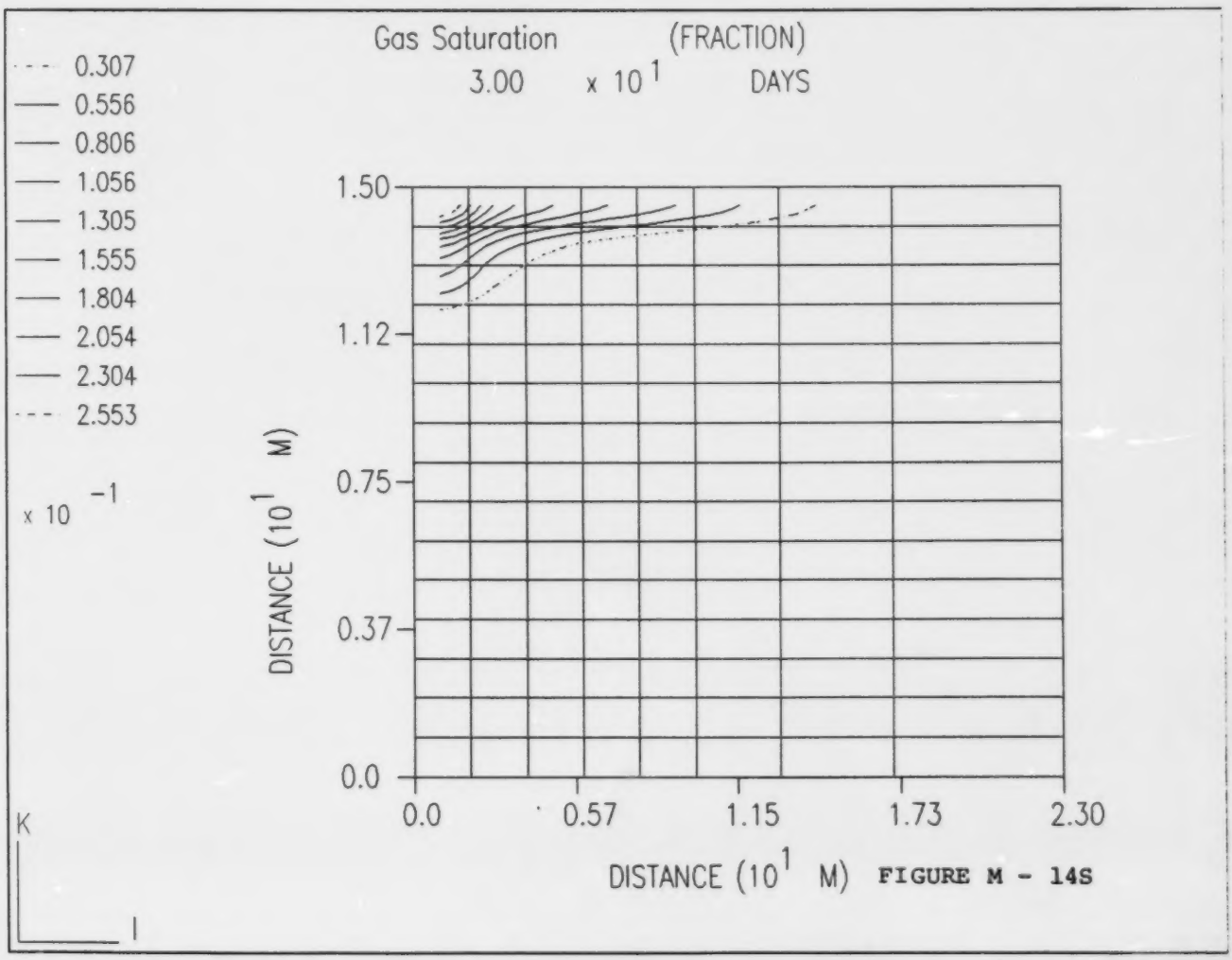

Gas Saturation (FRACTION)
3.00 x 10 1 DAYS
0.307
0.556
0.806
1.056
1.305
1.555
1.804
2.054
2.304
2.553
x 10 -1
1.50
1.12
0.75
0.37
0.0
DISTANCE (10 1 M)
0.0
0.57
1.15
1.73
2.30
DISTANCE (10 1 M)
K
I

FIGURE M - 14S

APPENDICES

APPENDIX 1

DEFINITIONS OF SYMBOLS AND UNITS

SYMBOL	UNITS	DEFINITION
Bt_{DV}		Dimensionless Time Group (EE&A) employed in Type Curve Match
c	kPa^{-1}	Compressibility
delh	M	Thickness of Low Permeability Layer (EE&A)
delp	kPa	Pressure Change from Initial Value, Measured at Offset Well at Time t
$delp_1$	kPa	Pressure Change from Initial Value, Measured at Same-Well Observation Point @ t = 1 hour
$delp_2$	kPa	Pressure Change from Initial Value, Measured @ Same-Well Observation Point
F		Dimensionless Parameter (Prats) related to Dimensionless Positions (z'/h and z/h)
h	M	Formation Thickness
h_1	M	Thickness of Zone Receiving Injection (EE&A)
h_2	M	Thickness of Zone Not Receiving Injection (EE&A)
k	μM^2	Permeability
k_v	μM^2	Vertical Permeability
k_h	μM^2	Horizontal Permeability
m	kPa/cyc	Slope of Pressure Charge-up/Fall-off Plot
p	kPa	Pressure
p_D		Dimensionless Pressure Change
p_{2D}		Dimensionless Pressure Change @ Same-Well Observation Point
p(t)	kPa	Pressure - Time-Varying
p_i	kPa	Pressure - Initial or Reference Pressure
$p_n(t)$	kPa	Pressure - Normalized Pressure
q	M^3D	Injection/Production Rate
q(t)	M^3D	Injection/Production Rate - Time-Varying
q_c	M^3D	Injection/Production Rate - Constant
r	M	Radius, Radial Distance
r_w	M	Well Radius
t	D	Time
z'	M	Distance of Injection Zone above Base of Formation
z	M	Distance of Same Well Observation Point above Base of Formation
μ	mPa.S	Viscosity
ϕ	fraction	Porosity

UPC

APPENDIX 2

DATA INPUT FOR THREE GAS INJECTION CASES RUN WITH IMEX 300

COMMON PARAMETERS AND CONDITIONS:

INITIAL PRESSURE, kPA	1000.0
POROSITY	0.03
COMPRESSIBILITY, kPa^{-1}	1.45E-06
WATER VISCOSITY, mPa.S	1.0
GAS VISCOSITY, mPa.S	0.012
FORMATION THICKNESS, M	15.0
WELL RADIUS, M	0.0762

CASE 1 (Prats):

HORIZONTAL PERMEABILITY, μM^2	9.869E-05
VERTICAL PERMEABILITY, μM^2	9.869E-06
GAS INJ.RATE, M^3/D @ STD.COND.	0.50
HYDROSTATIC GRADIENT (HEAD)	NOT INCLUDED

CASE 2 (EE&A):

PERMEABILITY (LOWER 7 M), μM^2	9.868E-05
PERMEABILITY (1M LOW K LAYER), μM^2	0.725E-06
PERMEABILITY (UPPER 7 M), μM^2	1.974E-04
GAS INJ.RATE, M^3/D @ STD.COND.	0.50
HYDROSTATIC GRADIENT (HEAD)	INCLUDED

CASE 3 (EE&A):

PERMEABILITY (LOWER 7 M), μM^2	9.868E-05
PERMEABILITY (1M LOW K LAYER), μM^2	0.725E-06
PERMEABILITY (UPPER 7 M), μM^2	1.974E-04
CONSTANT BH PRESSURE, kPa	1200.0
HYDROSTATIC GRADIENT (HEAD)	INCLUDED

CASE 1

```
**DGEN Generated Dataset **
**SECTION: GENERAL CONTROL CARDS:

** CON 1  'TITLE' - in quotes (maximum 40 characters)

'PART.COMP GAS INJ/SI;VR=83.3;NO HEAD'
** CON 2  'CASEID' - in quotes (maximum 8 characters)

'CASE 1  '
** CON 3  NX,NY,NZ,IGRID

   19    1   15    3
** CON 4  IGAS,ISOL

    1    0
** CON 5  NIN,NTMAX,IMPS

    0   70    0
** CON 6  NPR,NPRW,NRS,NPLT,NPLTW,INFO

    1    1    0    1    1    1
** CON 7  (IOUT(I),I=1,9) - SO,SG,SW,0,P,PB,POT,0,IM/EX

    1    1    1    0    1    0    0    0    1
** CON 8  (IOUTP(I),I=1,8) - SO,SG,SW,0,P,PB,POT,0

    1    1    1    0    1    0    0    0
** CON 9  IEQUIL

    1
** CON 10  IOPAR

    2
** CON 11  (DNORM(I),I=1,2)

  1000.000 0.1000000
** CON 13  IBKWDT,EIGNBK

 9999 0.8000000
** CON 14  NCYC,NITMAX,NORTH,IMOD,IFAC,IDEG,ISCALP

   10   30   10    0    1    1    1
** CON 15  (CTOL(IN),IN=1,2),RTOL

   5.00000 0.0050000 0.1000000
** CON 16  SDAY SMONTH SYEAR

    9    5 1989
** CON 17  DAY MONTH YEAR

    1    1 1989
** CON 18  NCRD - NUMBER OF CARDS OF THE FORM: I1,J1,K1,IRF,ITYPE

    0
** CON 21  GR,THETA,GZ

       0.0       0.0  -1.00000
**SECTION: RESERVOIR DESCRIPTION:

** RES 1  NCRD - NUMBER OF CARDS OF THE FORM: I1,I2,I3,DX OR DR
```

```
   14
** RES 3  I1,I2,I3,DR

    1    1    1   2.00000
    2    5    1   2.00000
    6    6    1   3.00000
    7    7    1   4.00000
    8    8    1   6.00000
    9    9    1   7.00000
   10   10    1  10.00000
   11   11    1  15.00000
   12   14    1  25.00000
   15   15    1    1.0000
   16   16    1   100.000
   17   17    1   200.000
   18   18    1  1000.000
   19   19    1 10000.000
** RES 4  NCRD - NUMBER OF CARDS OF THE FORM: J1,J2,J3,DY OR DTHETA

    1
** RES 6  J1,J2,J3,DTHETA

    1    0    1   1.00000
** RES 7  NCRD - NUMBER OF CARDS OF THE FORM: K1,K2,K3,DZ

    1
** RES 8  K1,K2,K3,DZ

    1    0    1   1.0000
** RES 15  NCRD - NUMBER OF CARDS OF THE FORM: I1,I2,J1,J2,K1,K2,PORI

    1
** RES 16  I1,I2,J1,J2,K1,K2,PORI

    1    0    1    0    1    0 0.0300000
** RES 18  NCRD - NUMBER OF CARDS OF THE FORM:
I1,I2,J1,J2,K1,K2,KX,KY,KZ
    1
** RES 19  I1,I2,J1,J2,K1,K2,KX,KY,KZ

    1    0    1    0    1    0 9.8690E-5 9.8690E-5 9.8690E-6
** RES 23  NCRD - NUMBER OF CARDS OF THE FORM:
I1,I2,J1,J2,K1,K2,TRMX,TRMY,TRMZ
    1
** RES 24  I1,I2,J1,J2,K1,K2,TRMX,TRMY,TRMZ

    1    0    1    0    1    0   1.00000   1.00000   1.00000
** RES 25  NSECTR - NUMBER OF SECTORS

    0
** RES 27  NLEASL - NUMBER OF LEASE-LINES

    0
**SECTION: RESERVOIR DESCRIPTION INITIAL CONDITIONS:

** INIT 1  NCRD - NUMBER OF CARDS OF THE FORM: I1,I2,J1,J2,K1,K2,P,PB

    1
** INIT 2  I1,I2,J1,J2,K1,K2,P,PB
```

```
    1    0    1    0    1    0  1000.000  1000.000
** INIT 9  NCRD - NUMBER OF CARDS OF THE FORM: I1,I2,J1,J2,K1,K2,SW,SO

    1
** INIT 10  I1,I2,J1,J2,K1,K2,SW,SO

    1    0    1    0    1    0   1.00000       0.0
**SECTION: MAINFRAME COMPATIBILITY DATA

**SECTION: PVT DATA:

** PVT 1  NCRD - NUMBER OF CARDS OF THE FORM: P,RS,BO,EG,VISO,VISG

    2
** PVT 2  P,RS,BO,EG,VISO,VISG

  1000.000       0.02   1.00000  10.00000   1.00000   0.012
 10000.000       0.03   1.00000  100.0000   1.00000   0.012
** PVT 5  DENOS,DENGS,DENWS,DENSS

  1000.000   0.1000    0.1000       0.0
** PVT 6  CO,CVISO

 1.4500E-6       0.0
** PVT 7  CPOR,PRPOR

       0.0  1000.000
** PVT 8  BWI,CW,PRW,VISWI,CVISW

   1.00000 1.4500E-6  1000.000   1.00000       0.0
**SECTION: ROCK FLUID PROPERTIES:

** REL 1  NRKTYP - NUMBER OF ROCK TYPES

    1
** REL 2  NCRD - NUMBER OF CARDS OF THE FORM: SW,KRW,KROW,PCOW

    11
** REL 3  SW,KRW,KROW,PCOW

       0.0   0.00000       0.0       0.0
       0.1   0.01000       0.0       0.0
       0.2   0.04000       0.0       0.0
       0.3   0.09000       0.0       0.0
       0.4   0.16000       0.0       0.0
       0.5   0.25000       0.0       0.0
       0.6   0.36000       0.0       0.0
       0.7   0.49000       0.0       0.0
       0.8   0.64000       0.0       0.0
       0.9   0.81000       0.0       0.0
   1.00000   1.00000       0.0       0.0
** REL 4  NCRD - NUMBER OF CARDS OF THE FORM: SL,KRG,KROG,PCOG

    11
** REL 5  SL,KRG,KROG,PCOG

       0.0   1.00000       0.0       0.0
       0.1   0.99000       0.0       0.0
       0.2   0.96000       0.0       0.0
```

```
       0.3   0.91000       0.0       0.0
       0.4   0.84000       0.0       0.0
       0.5   0.75000       0.0       0.0
       0.6   0.64000       0.0       0.0
       0.7   0.51000       0.0       0.0
       0.8   0.36000       0.0       0.0
       0.9   0.19000       0.0       0.0
   1.00000   0.00000       0.0       0.0
** REL 6  NCRD - NUMBER OF CARDS OF THE FORM:
I1,I2,J1,J2,K1,K2,IRF,ITYPE
    1
** REL 7  I1,I2,J1,J2,K1,K2,IRF,ITYPE - ENTER 1 FOR IRF

    1    0    1    0    1    0    1    1
**SECTION: WELL INPUT:

** WELL 1  NVRI

    0
** WELL 5  DTMAX,RDATE,IMON,IYER,ITSC

   2.000       0.0    0    0    1
** WELL 6  DWT

     0.001
** WELL 7  NWELLS - NO. OF WELLS

     1
** WELL 8   IW, IWS

     1    3
** WELL 9  'WELNAM' - in quotes (maximum 16 characters)

'GINJW1'
** WELL 10  IWT

    7
** WELL 11  NLY,IDIR

    1    3
** WELL 12  I,J,K,IRF

    1    1    12    1
** WELL 14  RW,CC,FF,SS,FH1,FHNLY

   0.0762   0.5   1.0   0.0   1.0   1.0
** WELL 16  NCRD - NUMBER OF CARDS OF THE FORM: ISPEC,MAXMIN,WSPEC

     2
** WELL 17  ISPEC,MAXMIN,WSPEC

     3    1    0.500000
** WELL 17  ISPEC,MAXMIN,WSPEC

     3   -1    1E-9
** WELL 18  ITERMC, ITERMV

     1    1
** WELL 21  ITERMB
```

```
    0
** WELL 23  IMPWI

    3
** WELL 24  NCRD - NO. OF CARDS OF FORM: I1,I2,J1,J2,K1,K2,IMPL,IRF

    0
** WELL 26  IMPW

    3
** WELL 27  DTMAX,RDATE,IMON,IYER,ITSC

      0.0       -30.0    0    0   1
** WELL 6   DTW

      0.025
** WELL 7   NWELLS

        1
** WELL 8   IW, IWS

    1     5
** WELL 22   WSPEC

       1.0E-8
** WELL 23 IMPWI

        3
** WELL 24 NCRD - NO. OF CARDS OF FORM I1,I2,J1,J2,K1,K2,IMPL,IRF

        0
** WELL 26 IMPW

        3
** WELL 27 DTMAX,RDATE,IMON,IYER,ITSC

    0.0,   -30.025   0   0   -1
```

CASE 2

```
**DGEN Generated Dataset **
**SECTION: GENERAL CONTROL CARDS:

** CON 1  'TITLE' - in quotes (maximum 40 characters)

'PART.COMP GAS INJ/SI;VR=83.3;HEAD'
** CON 2  'CASEID' - in quotes (maximum 8 characters)

'CASE 2  '
** CON 3  NX,NY,NZ,IGRID

   19    1   15    3
** CON 4  IGAS,ISOL

    1    0
** CON 5  NIN,NTMAX,IMPS

    0   70    0
** CON 6  NPR,NPRW,NRS,NPLT,NPLTW,INFO

    1    1    0    1    1    1
** CON 7  (IOUT(I),I=1,9) - SO,SG,SW,0,P,PB,POT,0,IM/EX

    1    1    1    0    1    0    0    0    1
** CON 8  (IOUTP(I),I=1,8) - SO,SG,SW,0,P,PB,POT,0

    1    1    1    0    1    0    0    0
** CON 9  IEQUIL

    1
** CON 10  IOPAR

    2
** CON 11  (DNORM(I),I=1,2)

  1000.000 0.1000000
** CON 13  IBKWDT,EIGNBK

 9999 0.8000000
** CON 14  NCYC,NITMAX,NORTH,IMOD,IFAC,IDEG,ISCALP

   10   30   10    0    1    1    1
** CON 15  (CTOL(IN),IN=1,2),RTOL

   5.00000 0.0050000 0.1000000
** CON 16  SDAY SMONTH SYEAR

    9    5 1989
** CON 17  DAY MONTH YEAR

    1    1 1989
** CON 18  NCRD - NUMBER OF CARDS OF THE FORM: I1,J1,K1,IRF,ITYPE

    0
** CON 21  GR,THETA,GZ

       0.0       0.0  -1.00000
**SECTION: RESERVOIR DESCRIPTION:

** RES 1  NCRD - NUMBER OF CARDS OF THE FORM: I1,I2,I3,DX OR DR
```

```
   14
** RES 3  I1,I2,I3,DR

    1    1    1   2.00000
    2    5    1   2.00000
    6    6    1   3.00000
    7    7    1   4.00000
    8    8    1   6.00000
    9    9    1   7.00000
   10   10    1  10.00000
   11   11    1  15.00000
   12   14    1  25.00000
   15   15    1    1.0000
   16   16    1   100.000
   17   17    1   200.000
   18   18    1  1000.000
   19   19    1 10000.000
** RES 4  NCRD - NUMBER OF CARDS OF THE FORM: J1,J2,J3,DY OR DTHETA

    1
** RES 6  J1,J2,J3,DTHETA

    1    0    1   1.00000
** RES 7  NCRD - NUMBER OF CARDS OF THE FORM: K1,K2,K3,DZ

    1
** RES 8  K1,K2,K3,DZ

    1    0    1   1.0000
** RES 15  NCRD - NUMBER OF CARDS OF THE FORM: I1,I2,J1,J2,K1,K2,PORI

    1
** RES 16  I1,I2,J1,J2,K1,K2,PORI

    1    0    1    0    1    0 0.0300000
** RES 18  NCRD - NUMBER OF CARDS OF THE FORM:
I1,I2,J1,J2,K1,K2,KX,KY,KZ
    3
** RES 19  I1,I2,J1,J2,K1,K2,KX,KY,KZ

    1    0    1    0    1    7 9.8690E-5 9.8690E-5 9.8690E-5
    1    0    1    0    8    8 0.7250E-6 0.7250E-6 0.7250E-6
    1    0    1    0    9   15 1.9738E-4 1.9738E-4 1.9738E-4
** RES 23  NCRD - NUMBER OF CARDS OF THE FORM:
I1,I2,J1,J2,K1,K2,TRMX,TRMY,TRMZ
    1
** RES 24  I1,I2,J1,J2,K1,K2,TRMX,TRMY,TRMZ

    1    0    1    0    1    0   1.00000   1.00000   1.00000
** RES 25  NSECTR - NUMBER OF SECTORS

    0
** RES 27  NLEASL - NUMBER OF LEASE-LINES

    0
**SECTION: RESERVOIR DESCRIPTION INITIAL CONDITIONS:

** INIT 1  NCRD - NUMBER OF CARDS OF THE FORM: I1,I2,J1,J2,K1,K2,P,PB
```

```
    15
** INIT 2  I1,I2,J1,J2,K1,K2,P,PB

    1    0    1    0    1    1  1068.600  1068.6
    1    0    1    0    2    2  1058.800  1058.8
    1    0    1    0    3    3  1049.000  1049.0
    1    0    1    0    4    4  1039.200  1039.2
    1    0    1    0    5    5  1029.400  1029.4
    1    0    1    0    6    6  1019.600  1019.6
    1    0    1    0    7    7  1009.800  1009.8
    1    0    1    0    8    8  1000.000  1000.0
    1    0    1    0    9    9   990.200   990.2
    1    0    1    0   10   10   980.400   980.4
    1    0    1    0   11   11   970.600   970.6
    1    0    1    0   12   12   960.800   960.8
    1    0    1    0   13   13   951.000   951.0
    1    0    1    0   14   14   941.200   941.2
    1    0    1    0   15   15   931.400   931.4
** INIT 9  NCRD - NUMBER OF CARDS OF THE FORM: I1,I2,J1,J2,K1,K2,SW,SO

    1
** INIT 10  I1,I2,J1,J2,K1,K2,SW,SO

    1    0    1    0    1    0   1.00000       0.0
**SECTION: MAINFRAME COMPATIBILITY DATA

**SECTION: PVT DATA:

** PVT 1  NCRD - NUMBER OF CARDS OF THE FORM: P,RS,BO,EG,VISO,VISG

    2
** PVT 2  P,RS,BO,EG,VISO,VISG

  1000.000       0.02   1.00000  10.00000   1.00000   0.012
 10000.000       0.03   1.00000  100.0000   1.00000   0.012
** PVT 5  DENOS,DENGS,DENWS,DENSS

  1000.000   1.1800    1000.0       0.0
** PVT 6  CO,CVISO

 1.4500E-6       0.0
** PVT 7  CPOR,PRPOR

       0.0  1000.000
** PVT 8  BWI,CW,PRW,VISWI,CVISW

   1.00000 1.4500E-6  1000.000   1.00000       0.0
**SECTION: ROCK FLUID PROPERTIES:

** REL 1  NRKTYP - NUMBER OF ROCK TYPES

    1
** REL 2  NCRD - NUMBER OF CARDS OF THE FORM: SW,KRW,KROW,PCOW

    11
** REL 3  SW,KRW,KROW,PCOW

       0.0   0.00000       0.0       0.0
       0.1   0.01000       0.0       0.0
       0.2   0.04000       0.0       0.0
```

```
      0.3   0.09000       0.0       0.0
      0.4   0.16000       0.0       0.0
      0.5   0.25000       0.0       0.0
      0.6   0.36000       0.0       0.0
      0.7   0.49000       0.0       0.0
      0.8   0.64000       0.0       0.0
      0.9   0.81000       0.0       0.0
  1.00000   1.00000       0.0       0.0
** REL 4  NCRD - NUMBER OF CARDS OF THE FORM: SL,KRG,KROG,PCOG

   11
** REL 5  SL,KRG,KROG,PCOG

      0.0   1.00000       0.0       0.0
      0.1   0.99000       0.0       0.0
      0.2   0.96000       0.0       0.0
      0.3   0.91000       0.0       0.0
      0.4   0.84000       0.0       0.0
      0.5   0.75000       0.0       0.0
      0.6   0.64000       0.0       0.0
      0.7   0.51000       0.0       0.0
      0.8   0.36000       0.0       0.0
      0.9   0.19000       0.0       0.0
  1.00000   0.00000       0.0       0.0
** REL 6  NCRD - NUMBER OF CARDS OF THE FORM:
I1,I2,J1,J2,K1,K2,IRF,ITYPE
   1
** REL 7  I1,I2,J1,J2,K1,K2,IRF,ITYPE - ENTER 1 FOR IRF

   1   0   1   0   1   0   1   1
**SECTION: WELL INPUT:

** WELL 1  NVRI

   0
** WELL 5  DTMAX,RDATE,IMON,IYER,ITSC

    2.000       0.0   0   0   1
** WELL 6  DWT

    0.001
** WELL 7  NWELLS - NO. OF WELLS

    1
** WELL 8   IW, IWS

    1   3
** WELL 9  'WELNAM' - in quotes (maximum 16 characters)

'GINJW1'
** WELL 10  IWT

   7
** WELL 11  NLY,IDIR

   1   3
** WELL 12  I,J,K,IRF

   1   1   15   1
** WELL 14  RW,CC,FF,SS,FH1,FHNLY
```

```
  0.0762   0.5   1.0   0.0   1.0   1.0
** WELL 16  NCRD - NUMBER OF CARDS OF THE FORM: ISPEC,MAXMIN,WSPEC

    2
** WELL 17  ISPEC,MAXMIN,WSPEC

    3    1    0.500000
** WELL 17  ISPEC,MAXMIN,WSPEC

    3   -1    1E-9
** WELL 18  ITERMC, ITERMV

    1    1
** WELL 21  ITERMB

    0
** WELL 23  IMPWI

   3
** WELL 24  NCRD - NO. OF CARDS OF FORM: I1,I2,J1,J2,K1,K2,IMPL,IRF

   0
** WELL 26  IMPW

   3
** WELL 27  DTMAX,RDATE,IMON,IYER,ITSC

      0.0       -30.0    0    0   1
** WELL 6   DTW

      0.025
** WELL 7   NWELLS

       1
** WELL 8   IW, IWS

    1     5
** WELL 22   WSPEC

       1.0E-8
** WELL 23 IMPWI

       3
** WELL 24 NCRD - NO. OF CARDS OF FORM I1,I2,J1,J2,K1,K2,IMPL,IRF

       0
** WELL 26 IMPW

       3
** WELL 27 DTMAX,RDATE,IMON,IYER,ITSC

    0.0,   -30.025   0   0   -1
```

CASE 3

```
**DGEN Generated Dataset **
**SECTION: GENERAL CONTROL CARDS:

** CON 1  'TITLE' - in quotes (maximum 40 characters)

'PART.COMP GAS INJ/SI;VR=83.3;HEAD'
** CON 2  'CASEID' - in quotes (maximum 8 characters)

'CASE 3  '
** CON 3  NX,NY,NZ,IGRID

   19    1   15    3
** CON 4  IGAS,ISOL

    1    0
** CON 5  NIN,NTMAX,IMPS

    0   70    0
** CON 6  NPR,NPRW,NRS,NPLT,NPLTW,INFO

    1    1    0    1    1    1
** CON 7  (IOUT(I),I=1,9) - SO,SG,SW,0,P,PB,POT,0,IM/EX

    1    1    1    0    1    0    0    0    1
** CON 8  (IOUTP(I),I=1,8) - SO,SG,SW,0,P,PB,POT,0

    1    1    1    0    1    0    0    0
** CON 9  IEQUIL

    1
** CON 10  IOPAR

    2
** CON 11  (DNORM(I),I=1,2)

  1000.000 0.1000000
** CON 13  IBKWDT,EIGNBK

 9999 0.8000000
** CON 14  NCYC,NITMAX,NORTH,IMOD,IFAC,IDEG,ISCALP

   10   30   10    0    1    1    1
** CON 15  (CTOL(IN),IN=1,2),RTOL

   5.00000 0.0050000 0.1000000
** CON 16  SDAY SMONTH SYEAR

    9    5 1989
** CON 17  DAY MONTH YEAR

    1    1 1989
** CON 18  NCRD - NUMBER OF CARDS OF THE FORM: I1,J1,K1,IRF,ITYPE

    0
** CON 21  GR,THETA,GZ

       0.0       0.0  -1.00000
**SECTION: RESERVOIR DESCRIPTION:

** RES 1  NCRD - NUMBER OF CARDS OF THE FORM: I1,I2,I3,DX OR DR
```

```
   14
** RES 3  I1,I2,I3,DR

    1    1    1   2.00000
    2    5    1   2.00000
    6    6    1   3.00000
    7    7    1   4.00000
    8    8    1   6.00000
    9    9    1   7.00000
   10   10    1  10.00000
   11   11    1  15.00000
   12   14    1  25.00000
   15   15    1    1.0000
   16   16    1   100.000
   17   17    1   200.000
   18   18    1  1000.000
   19   19    1 10000.000
** RES 4  NCRD - NUMBER OF CARDS OF THE FORM: J1,J2,J3,DY OR DTHETA

    1
** RES 6  J1,J2,J3,DTHETA

    1    0    1   1.00000
** RES 7  NCRD - NUMBER OF CARDS OF THE FORM: K1,K2,K3,DZ

    1
** RES 8  K1,K2,K3,DZ

    1    0    1   1.0000
** RES 15  NCRD - NUMBER OF CARDS OF THE FORM: I1,I2,J1,J2,K1,K2,PORI

    1
** RES 16  I1,I2,J1,J2,K1,K2,PORI

    1    0    1    0    1    0 0.0300000
** RES 18  NCRD - NUMBER OF CARDS OF THE FORM:
I1,I2,J1,J2,K1,K2,KX,KY,KZ
    3
** RES 19  I1,I2,J1,J2,K1,K2,KX,KY,KZ

    1    0    1    0    1    7 9.8690E-5 9.8690E-5 9.8690E-5
    1    0    1    0    8    8 0.7250E-6 0.7250E-6 0.7250E-6
    1    0    1    0    9   15 1.9738E-4 1.9738E-4 1.9738E-4
** RES 23  NCRD - NUMBER OF CARDS OF THE FORM:
I1,I2,J1,J2,K1,K2,TRMX,TRMY,TRMZ
    1
** RES 24  I1,I2,J1,J2,K1,K2,TRMX,TRMY,TRMZ

    1    0    1    0    1    0   1.00000   1.00000   1.00000
** RES 25  NSECTR - NUMBER OF SECTORS

    0
** RES 27  NLEASL - NUMBER OF LEASE-LINES

    0
**SECTION: RESERVOIR DESCRIPTION INITIAL CONDITIONS:

** INIT 1  NCRD - NUMBER OF CARDS OF THE FORM: I1,I2,J1,J2,K1,K2,P,PB
```

```
   15
** INIT 2  I1,I2,J1,J2,K1,K2,P,PB

   1    0    1    0    1    1  1068.600  1068.6
   1    0    1    0    2    2  1058.800  1058.8
   1    0    1    0    3    3  1049.000  1049.0
   1    0    1    0    4    4  1039.200  1039.2
   1    0    1    0    5    5  1029.400  1029.4
   1    0    1    0    6    6  1019.600  1019.6
   1    0    1    0    7    7  1009.800  1009.8
   1    0    1    0    8    8  1000.000  1000.0
   1    0    1    0    9    9   990.200   990.2
   1    0    1    0   10   10   980.400   980.4
   1    0    1    0   11   11   970.600   970.6
   1    0    1    0   12   12   960.800   960.8
   1    0    1    0   13   13   951.000   951.0
   1    0    1    0   14   14   941.200   941.2
   1    0    1    0   15   15   931.400   931.4
** INIT 9  NCRD - NUMBER OF CARDS OF THE FORM: I1,I2,J1,J2,K1,K2,SW,SO

   1
** INIT 10  I1,I2,J1,J2,K1,K2,SW,SO

   1    0    1    0    1    0   1.00000       0.0
**SECTION: MAINFRAME COMPATIBILITY DATA

**SECTION: PVT DATA:

** PVT 1  NCRD - NUMBER OF CARDS OF THE FORM: P,RS,BO,EG,VISO,VISG

   2
** PVT 2  P,RS,BO,EG,VISO,VISG

  1000.000       0.02   1.00000  10.00000   1.00000   0.012
 10000.000       0.03   1.00000  100.0000   1.00000   0.012
** PVT 5  DENOS,DENGS,DENWS,DENSS

  1000.000   1.1800    1000.0       0.0
** PVT 6  CO,CVISO

 1.4500E-6       0.0
** PVT 7  CPOR,PRPOR

       0.0  1000.000
** PVT 8  BWI,CW,PRW,VISWI,CVISW

   1.00000 1.4500E-6  1000.000   1.00000       0.0
**SECTION: ROCK FLUID PROPERTIES:

** REL 1  NRKTYP - NUMBER OF ROCK TYPES

   1
** REL 2  NCRD - NUMBER OF CARDS OF THE FORM: SW,KRW,KROW,PCOW

   11
** REL 3  SW,KRW,KROW,PCOW

       0.0   0.00000       0.0       0.0
       0.1   0.01000       0.0       0.0
       0.2   0.04000       0.0       0.0
```

```
      0.3   0.09000       0.0       0.0
      0.4   0.16000       0.0       0.0
      0.5   0.25000       0.0       0.0
      0.6   0.36000       0.0       0.0
      0.7   0.49000       0.0       0.0
      0.8   0.64000       0.0       0.0
      0.9   0.81000       0.0       0.0
  1.00000   1.00000       0.0       0.0
** REL 4  NCRD - NUMBER OF CARDS OF THE FORM: SL,KRG,KROG,PCOG

   11
** REL 5  SL,KRG,KROG,PCOG

      0.0   1.00000       0.0       0.0
      0.1   0.99000       0.0       0.0
      0.2   0.96000       0.0       0.0
      0.3   0.91000       0.0       0.0
      0.4   0.84000       0.0       0.0
      0.5   0.75000       0.0       0.0
      0.6   0.64000       0.0       0.0
      0.7   0.51000       0.0       0.0
      0.8   0.36000       0.0       0.0
      0.9   0.19000       0.0       0.0
  1.00000   0.00000       0.0       0.0
** REL 6  NCRD - NUMBER OF CARDS OF THE FORM:
I1,I2,J1,J2,K1,K2,IRF,ITYPE
   1
** REL 7  I1,I2,J1,J2,K1,K2,IRF,ITYPE - ENTER 1 FOR IRF

   1   0   1   0   1   0   1   1
**SECTION: WELL INPUT:

** WELL 1  NVRI

   0
** WELL 5  DTMAX,RDATE,IMON,IYER,ITSC

    2.000       0.0    0    0    1
** WELL 6  DWT

    0.001
** WELL 7  NWELLS - NO. OF WELLS

    1
** WELL 8   IW, IWS

    1   3
** WELL 9  'WELNAM' - in quotes (maximum 16 characters)

'GINJW1'
** WELL 10  IWT

   7
** WELL 11  NLY,IDIR

   1   3
** WELL 12  I,J,K,IRF

   1   1   15   1
** WELL 14  RW,CC,FF,SS,FH1,FHNLY
```

```
   0.0762   0.5   1.0   0.0   1.0   1.0
** WELL 16  NCRD - NUMBER OF CARDS OF THE FORM: ISPEC,MAXMIN,WSPEC

     2
** WELL 17  ISPEC,MAXMIN,WSPEC

     6    1    1200
** WELL 17  ISPEC,MAXMIN,WSPEC

     6   -1    1E-9
** WELL 18  ITERMC, ITERMV

     1    1
** WELL 21  ITERMB

     0
** WELL 23  IMPWI

    3
** WELL 24  NCRD - NO. OF CARDS OF FORM: I1,I2,J1,J2,K1,K2,IMPL,IRF

    0
** WELL 26  IMPW

    3
** WELL 27  DTMAX,RDATE,IMON,IYER,ITSC

      0.0       -30.0    0    0   1
** WELL 6   DTW

      0.025
** WELL 7   NWELLS

        1
** WELL 8   IW, IWS

    1     5
** WELL 22   WSPEC

       1.0E-8
** WELL 23 IMPWI

        3
** WELL 24 NCRD - NO. OF CARDS OF FORM I1,I2,J1,J2,K1,K2,IMPL,IRF

        0
** WELL 26 IMPW

        3
** WELL 27 DTMAX,RDATE,IMON,IYER,ITSC

    0.0,   -30.025   0   0   -1
```